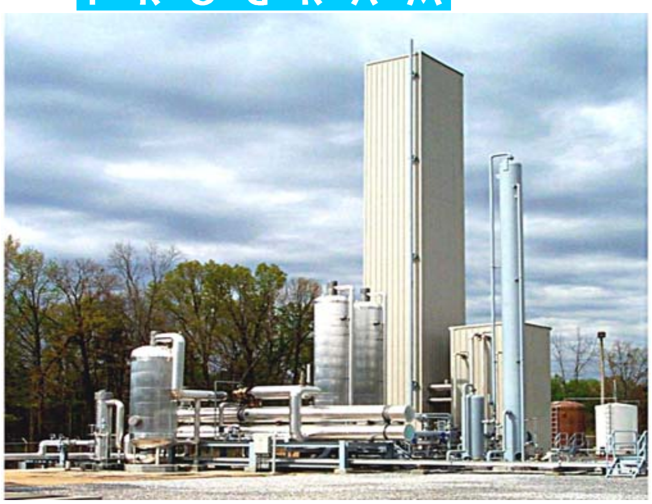
Identifying Opportunities for Methane Recovery at U.S. Coal Mines:

Profiles of Selected Gassy Underground Coal Mines 1997-2001

EPA Coalbed Methane Outreach Program



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COVER PHOTOGRAPHS (clockwise from top): 1) Two 44 MW Gas-Combustion Turbines Operated by Allegheny Energy and Consol Energy (Photo courtesy of Consol) 2) 850 kW Caterpillar engine at O'Gara #8 abandoned mine in Illinois Basin, Operated by Grayson Hill Farms (Photo Courtesy of Raven Ridge Resources, Incorporated) 3) BCCK Cryogenic Gas Processing Unit at JWR Blue Creek Mines (Photo courtesy of Jim Walters Resources)

ACKNOWLEDGMENTS

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Table of Contents

4. A Key to Evaluating Mine Profiles

5. Mine Summary Tables

6. Profiled Mines

Mine Profiles (profiles appear in alphabetical order by state)

List of Figures

Page #

List of Tables

Frequently Used Terms

Coalbed methane: Methane that resides within coal seams.

Coal mine methane: As coal mining proceeds, methane contained in the coal and surrounding strata may be released. This methane is referred to as coal mine methane since its liberation resulted from mining activity. In some instances, methane that continues to be released from the coal bearing strata once a mine is closed and sealed may also be referred to as coal mine methane because the liberated methane is associated with past coal mining activity.

Degasification system: A system that facilitates the removal of methane gas from a mine by ventilation and/or by drainage. However, the term is most commonly used to refer to removal of methane by drainage technology.

Drainage system: A system that drains methane from coal seams and/or surrounding rock strata. These systems include vertical pre-mine wells, gob wells and in-mine boreholes.

Ventilation system: A system that is used to control the concentration of methane within mine working areas. Ventilation systems consist of powerful fans that move large volumes of air through the mine workings to dilute methane concentrations.

Methane drained: The amount of methane removed via a drainage system.

Methane liberated: The total amount of methane that is released, or liberated, from the coal and surrounding rock strata during the mining process. This total is determined by summing the volume of methane emitted from the ventilation system and the volume of methane that is drained.

Methane recovered: The amount of methane that is captured through methane drainage systems and is synonymous with "methane drained."

Methane used: The amount of methane put to productive use (.e.g., natural gas pipeline injection, fuel for power generation, etc)

Methane emissions: This is the total amount of methane that is not used and therefore emitted to the atmosphere. Methane emissions are calculated by subtracting the amount of methane used from the amount of methane liberated (emissions = liberated – recovered/used).

Frequently Used Abbreviations

b	Billion (10^9)
Btu	British Thermal Unit
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
cf	Cubic Feet
CH_4	Methane
CO_2	Carbon Dioxide
DOE	Department of Energy
EIA	Energy Information Administration
EPA	Environmental Protection Agency
FOB	Freight on Board
GWP	Global Warming Potential
m (or M)	Thousand (10^3)
mm (or MM)	Million (10^6)
MSHA	Mine Safety and Health Administration
MW	Megawatt
NA	Not Available (as opposed to Not Applicable)
PUC	Public Utility Commission
t	ton (short tons are used throughout this report)
USBM	U.S. Bureau of Mines
UMWA	United Mine Workers of America

1. Executive Summary

1. Executive Summary

The purpose of this report is to provide information about specific opportunities to develop methane recovery projects at large underground coal mines in the United States. This report contains profiles of 50 U.S. coal mines that may be potential candidates for methane recovery and use, and details on-going recovery projects at 10 of the mines. The United States Environmental Protection Agency (EPA) designed the profiles to help project developers perform an initial screening of potential projects. While the mines profiled in this report appear to be good candidates, a detailed evaluation would need to be done on a site-specific basis in order to determine whether the development of a specific methane recovery project is both technically and economically feasible.

Since the last version of this report was published in September 1997, coalbed and coal mine methane recovery and use have continued to develop and grow from an estimated 28 Bcf in 1997 to over 40 Bcf in 2001. At a gas price of $3/mcf, this means that coal mine methane developers increased annual revenues by an estimated $36 million between 1997 and 2001.

Methane Emissions and Recovery Opportunities

Non-CO_2 gases play important roles in efforts to understand and address global climate change. The non-CO_2 gases include a broad category of greenhouse gases other than carbon dioxide (CO_2), such as methane, nitrous oxide and a number of high global warming potential (GWP) gases. The non-CO_2 gases are more potent thanCO_2 (per unit weight) and are significant contributors to global warming, thus, reducing emissions of non-CO_2 gases can help prevent global climate change and produce broader economic and environmental benefits.

Methane (CH_4) is a greenhouse gas that exists in the atmosphere for approximately 9-15 years. As a greenhouse gas, CH_4 is over 20 times more effective in trapping heat in the atmosphere than carbon dioxide (CO_2) over a 100-year period and is emitted from a variety of natural and human-influenced sources. Human-influenced sources include landfills, natural gas and petroleum systems, agricultural activities, coal mining, stationary and mobile combustion, wastewater treatment, and certain industrial process.

Methane is also a primary constituent of natural gas and an important energy source. As a result, efforts to prevent or utilize methane emissions can provide significant energy, economic and environmental benefits. In the United States, many companies are working with EPA in voluntary efforts to reduce emissions by implementing cost-effective management methods and technologies.

U.S. industries along with state and local governments collaborate with the U.S. Environmental Protection Agency to implement several voluntary programs that promote profitable opportunities for reducing emissions of methane, an important greenhouse gas. These programs are designed to overcome a wide range of informational, technical, and institutional barriers to reducing methane emissions, while creating profitable activities for the coal, natural gas, petroleum, landfill, and agricultural industries.

CMM Recovery Opportunities

In the US, coal mines account for approximately 10% of all man-made methane emissions. Today, there are methane recovery and use projects at mines in Alabama, Virginia, and West Virginia. As shown in this report, there are many additional gassy coal mines at which projects have not yet been developed that offer the potential for the profitable recovery of methane.

In addition to the direct financial benefits that may be enjoyed from the sale of coal mine methane, indirect financial and economic benefits may also be achieved. Degasification systems that are used to drain methane prevent gas from escaping into mine working areas, increase methane recovery, improve worker safety, and significantly reduce ventilation costs at several mines. Increased recovery also reduces methane-related mining delays, resulting in increased coal productivity. Furthermore, the development of methane recovery projects has been shown to result in the creation of new jobs, which has helped to stimulate area economies.[1] Additionally, the development of local coal mine methane resources may result in the availability of a potentially low-cost supply of gas that could be used to help attract new industry to a region. For these reasons, encouraging the development of coal mine methane recovery projects is likely to be of growing interest to state and local governments that have candidate mines in their jurisdictions.

For example, some of the mines profiled in this report have methane emissions in excess of ten million cubic feet per day (or nearly 4 billion cubic feet per year). To illustrate the impact of methane recovery, developing a project at mine recovering two billion cubic feet per year would result in emissions reductions of equating to 900,000 tonnes of CO_2.[2] Because of the large environmental benefits that may be achieved, coal mine methane projects may serve as cost-effective alternatives for utilities and others seeking to offset their own greenhouse gas emissions.

To realize continued emission reductions from the coal mining industry, EPA's Coalbed Methane Outreach Program The Coalbed Methane Outreach Program (CMOP) has worked voluntarily with the coal mining industry and associated industries since 1994 to recover and use methane (CH_4) released into and emitted from the mines.

CMOP's efforts are directed to assist the mining industry by supporting project development, overcoming institutional, technical, regulatory and financial barriers to implementation, and educating the general public on the benefits of CMM recovery. More specifically, these efforts include:

- identifying, evaluating and promoting methane reduction options including technological innovations and market mechanisms to encourage project implementation;
- workshops to educate the mining sector on the environmental, mine safety and economic benefits of methane recovery;
- preparing and disseminating reports and other materials that address topics ranging from technical and economic analyses to overviews of legal issues;
- interfacing with all facets of the industry to advance real project development;
- conducting pre-feasibility and feasibility studies for US mines that examine a range of end-use options; and
- managing a website that is an important information resource for the coal mine methane industry.

Overview of CMM Recovery and Use Techniques

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[1] For example, see discussion on this subject in the report "The Environmental and Economic Benefits of Coalbed Methane Development in the Appalachian Region" (USEPA, 1994).

[2] The carbon dioxide equivalent of methane emissions is calculated by determining the weight of methane collected (on a 100% basis), using a density of 19.2 g/cf. The weight is then multiplied by the global warming potential (GWP) of methane, which is 21 times greater than carbon dioxide over a 100 year time period.

Methane gas (CH_4) and coal are formed together during coalification, a process in which biomass is converted by biological and geological processes into coal. Methane is stored within coal seams and also within the rock strata surrounding the seams. Methane is released when pressure within a coalbed is reduced as a result of natural erosion, faulting, or mining. Deep coal seams tend to have a higher average methane content than shallow coal seams, because the capacity to store methane increases as pressure increases with depth. Accordingly, underground mines release substantially more methane than surface mines, per ton of coal extracted.

Coal mine methane emissions may be mitigated by the implementation of methane recovery projects at underground mines. Mines can use several reliable degasification methods to drain methane. These methods have been developed primarily to supplement mine ventilation systems that were designed to ensure that methane concentrations in underground mines remain within safe concentrations. While these degasification systems are mostly used for safety reasons, they can also recover methane that may be employed as an energy resource. Degasification systems include vertical wells (drilled from the surface into the coal seam months or years in advance of mining), gob wells (drilled from the surface into the coal seam just prior to mining), and in-mine boreholes (drilled from inside the mine into the coal seam or the surrounding strata prior to mining).

The quality (purity) of the gas that is recovered is partially dependent on the degasification method employed, and determines how the gas can be used. For example, only high quality gas (typically greater than 95% methane) can be used for pipeline injection. Vertical wells and horizontal boreholes tend to recover nearly pure methane (over 95% methane). In very gassy mines, gob wells can also recover high-quality methane, especially during the first few months of production. Over time, however, mine air may become mixed with the methane produced by gob wells, resulting in a lower quality gas.

Even lower quality methane can be used as an energy source in various applications. Potential applications that have been demonstrated in the U.S. and other countries include:

- electricity generation (the electricity can be used either on-site or can be sold to utilities);
- as a fuel for on-site preparation plants or mine vehicles, or for nearby industrial or institutional facilities; and,
- cutting-edge applications, such as in fuel cells and ventilation air methane (VAM) technologies.

It is also possible to enrich lower quality gas to pipeline standards using technologies that separate methane from carbon dioxide, oxygen, and/or nitrogen. Several technologies for separating methane are under development. Another option for improving the quality of mine gas is blending, which is the mixing of lower quality gas with higher quality gas whose heating value exceeds pipeline requirements.

Even mine ventilation air, which typically contains less than 1% methane, is being successfully used as combustion air in gas-fired internal combustion engines in Australia. The technology for using mine ventilation air as combustion air in turbines and coal-fired boilers also exists, and research on the use of thermal oxidizers and catalytic reactors to generate heat from methane in mine ventilation air is underway.

Opportunities for Methane Recovery Projects

While methane recovery projects already are operating at some of the gassiest mines in the U.S., there are numerous additional gassy mines at which recovery projects could be developed. This report profiles 50 mines that are potential candidates for the development of coal mine methane projects. At least 11 currently operate drainage systems, with drainage efficiencies in the range of 25 to 60 percent. Ten of the draining mines already sell recovered methane. [3] Mines that already use drainage systems may be especially good candidates for the development of cost-effective methane recovery projects. There are also projects at abandoned mines in the U.S.; however, this report only profiles active mines.

Overview of Methane Liberation, Drainage and Use at Profiled Mines

This report profiles mines located in 12 states. West Virginia has the largest number of profiled mines (12), followed by Kentucky (7), and Alabama (6). In 2001, the 50 mines profiled in this report liberated an estimated 336 mmcf/d of methane, or about 123 Bcf/yr (93% of all methane liberated from underground mines). Table 1-1 shows the number of profiled mines and the estimated total methane liberated from these mines, summarizing information presented in the state summaries and individual mine profiles (Chapter 6). Chapter 4 explains how these data were derived.

Table 1-1 shows that about 46% of the total estimated methane liberated from all profiled mines is being used. Table 1-1 also shows estimated annual methane emissions from the mines that are operating but not using methane and the estimated annual methane emissions that would be avoided by implementing methane recovery and use projects at these mines, assuming a 20-60% range of recovery efficiency. Based on these recovery efficiencies, if methane recovery projects were implemented at profiled mines that are currently operating but do not recover methane, an estimated 10-29 Bcf/yr of methane emissions would be avoided. This is equivalent to about 4-12 mmt/yr of CO_2. Moreover, there is significant potential for increased methane recovery at many of the mines that already have recovery projects.

[3] Please see Chapter 4 for a more detailed discussion of this issue.

Table 1-1: U.S. Summary Table Number of Profiled Mines and Estimated Methane Liberated and Used in 2001[1]							
	Operating but not Using Methane		Operating and Using Methane		All Mines Profiled in This Report		
State	Number of Mines	Total Methane Liberated (mmcf/d)	Number of Mines	Total Methane Liberated (mmcf/d)	Number of Mines	Total Methane Liberated (mmcf/d)	Estimated Methane Use (mmcf/d)
Alabama	1	5.6	5	79.7	6	85.3	37
Colorado	3	23.5	0	0.0	3	23.5	0
Illinois	5	14.2	0	0.0	5	14.2	0
Indiana	1	1.3	0	0.0	1	1.3	0
Kentucky	7	8.3	0	0.0	7	8.3	0
New Mexico	1	0.3	0	0.0	1	0.3	0
Ohio	2	2.2	0	0.0	2	2.2	0
Oklahoma	1	0.9	0	0.0	1	0.9	0
Pennsylvania	5	45.0	0	0.0	5	45.0	0
Utah	4	2.9	0	0.0	4	2.9	0
Virginia	1	0.6	2	88.5	3	89.1	107
West Virginia	19	28.8	3	34.5	12	63.3	9
TOTAL:	40	133.6	10	202.7	50	336.3	153
Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent from Operating Mines not Currently Using Methane (40 mines):						**Methane (Bcf/y)**	**CO_2 (mmt/y)**
2001 Estimated Total Emissions						48.8	19.5
Estimated Annual Avoided Emissions if Recovery Projects are Implemented						10.0 – 29.3	3.9 – 11.7
[1]Chapter 4 explains how these data were estimated.							

Summary of Opportunities for Project Development

Most underground coal mines still do not recover and use methane, however, the profiles indicate that many of these mines appear to be strong candidates for cost-effective recovery projects. Furthermore, this report contains information suggesting that substantial environmental, economic, and energy benefits could be achieved if mines that currently emit methane were to recover and use it.

The mines profiled in this report are quite variable in terms of the amount of methane they liberate, their gassiness or "specific emissions" (methane liberated per ton of coal mined), and their annual coal production. The volume of methane liberated from each mine ranges from less than 0.3 mmcf/d to over 70 mmcf/d. Similarly, specific emissions range from approximately 25 cf/ton to over 11,000 cf/ton. Annual coal production ranges from approximately 300,000 tons at some mines to over 10 million tons per year at others. All these factors are important indicators of the potential profitability of developing a project at an individual mine. Furthermore, as shown in the profiles (Chapter 6), the candidate mines vary with respect to other important factors that affect profitability, such as the distance from the mine to

a pipeline or the projected remaining productive life of the mine. Accordingly, the overall feasibility of developing a methane recovery project will likely vary widely among the candidate mines.
Although a number of the mines profiled here show strong potential for profitable projects, methane ventures at these mines are not currently being developed, due to a number of barriers to coal mine methane development. Many of these barriers are being overcome. Gas prices have improved, increasing the economic benefits of coalbed methane recovery. Restructuring of the gas industry has created new market opportunities for coal mine methane, and the potential for distributed generation is increasing as a result of electricity industry restructuring. At the same time, utilities and other industries are seeking opportunities to offset greenhouse gas emissions and to develop "environmentally friendly" projects. If projects are initiated at even a few of the mines profiled here, substantial methane emissions reductions and increased profits for developers could be achieved, thereby benefiting the U.S. economy and the global environment.

The following list summarizes the chapters in this report:

- Chapter 2 provides an introduction to coal mine methane in the U.S., including a discussion of major developments in the burgeoning coal mine methane recovery industry that have transpired since publication of the previous version of this report in 1997.
- Chapter 3 discusses current coal mine methane recovery projects in the U.S.
- Chapter 4 provides a key to evaluating the mine profiles.
- Chapter 5 presents the mine summary tables 5.
- Chapter 6 lists state summaries and actual mine profiles, which should assist potential investors in assessing the overall potential project profitability.

2. Introduction

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Purpose of Report

This report provides information about specific opportunities to develop methane recovery and use projects at large underground mines in the United States. Groups that may be interested in identifying such opportunities include utilities, natural gas resource developers, independent power producers, and local industries or institutions that could directly use the methane recovered from a nearby mine.

This introduction provides a broad overview of the technical, economic, regulatory, and environmental issues concerning methane recovery from coal mines. The report also presents an overview of existing methane recovery and use projects (Chapter 3). Chapter 4 contains Information that will assist the reader in understanding and evaluating the data presented in Chapters 5 and 6. Chapter 5 contains data summary tables, and finally, Chapter 6 profiles individual underground coal mines that appear to be good candidates for the development of methane recovery projects.

Recent Developments in the Coal Mine Methane Industry

Since the last version of this document was published in September 1997, there have been significant developments in coal mine methane recovery, particularly in the number of active recovery and use projects. The number of mines with active methane recovery and use projects has decreased from 14 in 1997 to ten in 2001. However, the amount of methane recovered has increased from an estimated 28 Bcf in 1997 to nearly 40 Bcf in 2001. At a gas price of $3/mcf, this means that coal mine methane developers increased revenues by an estimated $36 million from 1997 to 2001. The resulting decrease in methane emissions has yielded additional benefits to the global environment through greenhouse gas emission reductions of 5 MMT/year of CO_2. Figure 2-1 shows the number of mines engaging in coal mine methane recovery since 1994 while Figure 2-2 shows the growth in the amount of gas being recovered.

The growth in the amount of recovered methane can be attributed to five primary factors: 1) continued use in natural gas pipelines; 2) use for a variety of purposes besides pipeline injection; 3) legislation concerning ownership issues has been enacted in most coalbed methane producing states; 4) various projects have proven the profit-generating potential of coal mine methane recovery; and 5) growing awareness of the climate change impacts of methane emissions. Also, the issuance of FERC Orders 636 and 888 is removing barriers to free and open competition in the natural gas and electric utility industries, respectively. As a result of these orders, coal mine methane developers should encounter fewer problems accessing available capacity of the nation's gas and electric transmission lines.

Figure 2-1: Mines with Active Coal Mine Methane Recovery Projects

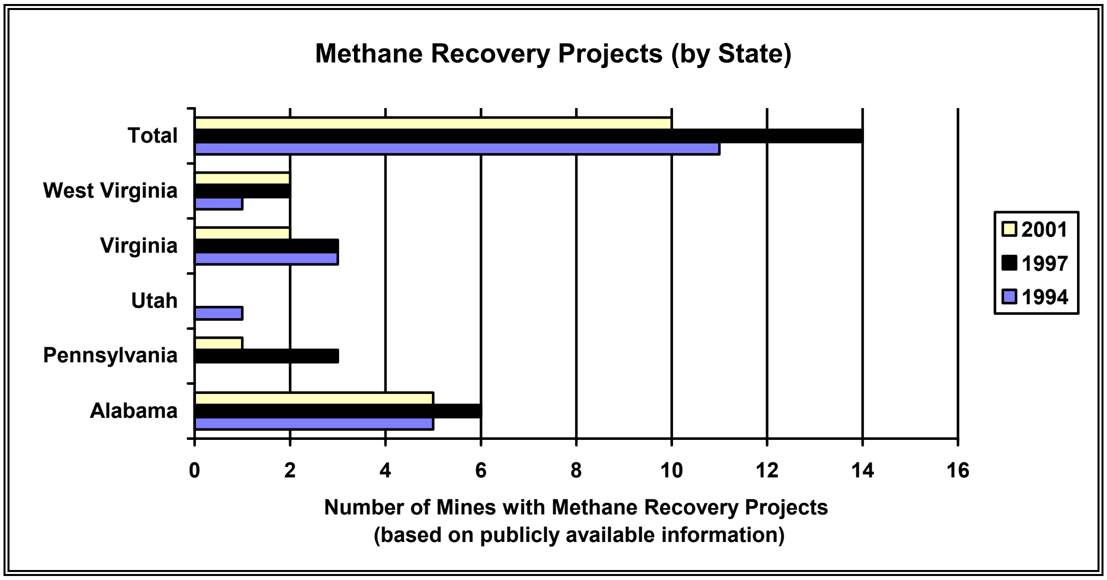
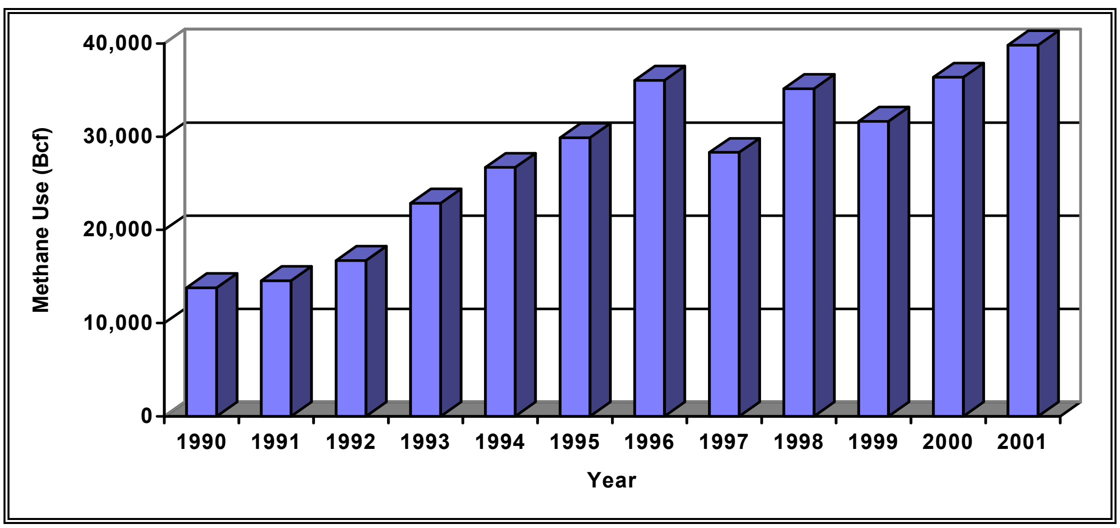


Figure 2-2: Estimated Annual Use of Methane Recovered From U.S. Coal Mines (based on publicly available information)



Overview of Coal Mine Methane

Methane and coal are formed together during coalification, a process in which vegetation is converted by geological and biological forces into coal. Methane is stored in large quantities within coal seams and also within the rock strata surrounding the seams. Two of the most important factors determining the amount of methane that will be stored in a coal seam and the surrounding strata are the rank and the depth of the coal. Coal is ranked by its carbon content; coals of a higher rank have a higher carbon content and generally a higher methane content.[4] The capacity to store methane increases as

[4] In descending order, the ranks of coal are: graphite, anthracite, bituminous, sub-bituminous, and lignite. Most U.S. production is bituminous or sub-bituminous.

pressure increases with depth. Thus, within a given coal rank, deep coal seams tend to have a higher methane content than shallow ones.

Methane concentrations typically increase with depth, therefore underground mines tend to release significantly higher quantities of methane per ton of coal mined than do surface mines. In 2001, while only 38 percent of U.S. coal is produced in underground mines, these mines account for over 70 percent of estimated methane emissions from coal mining (USEPA, 2003a). Although the options for recovering and using methane are primarily available for underground mines, gas recovery at surface mines may also be feasible. Among underground mines, the largest and gassiest mines typically have the best potential for profitable recovery and utilization of methane.

Methane emissions resulting from coal mining activities account for about 10 percent of annual global methane emissions from anthropogenic (man-made) sources. In 2001, The People's Republic of China was the largest emitter of coal mine methane, followed by the United States and then Russia, Ukraine and Australia (USEPA, 2001). In 2001, coal mining emissions were estimated to account for 10.0 percent of total U.S. methane emissions (USEPA, 2003a), down from 11.3 percent in 1995.

In underground mines, methane poses a serious safety hazard for miners because it is explosive in low concentrations (5 to 15 percent in air). In the U.S., methane concentrations in the mine may not exceed one percent in mine working areas and two percent in all other locations. In many underground mines, methane emissions can be controlled solely through the use of a ventilation system, which pumps large quantities of air through the mine in order to dilute the methane to safe levels, but, the CMM released to the atmosphere by the mine ventilation system is typically below 1 percent. This methane vented from a coal mine exhaust shafts constitutes the largest source of coal mine methane emissions in the U.S. In 2001, for example, 84 billion cubic feet (Bcf) or 64% of the 132 Bcf released from underground mines was released through mine ventilation shafts.

In particularly gassy mines, however, the ventilation system must be supplemented with a drainage system. Drainage systems reduce the quantity of methane in the working areas by draining the gas from the coal-bearing strata before, during, or after mining, depending on mining needs. Emissions from drainage systems are estimated to account for approximately one third of the total methane emissions from underground coal mining. At least 20 of the mines profiled in this report have some type of drainage system.

Methane Drainage Techniques

Over the years, mine operators have realized the economic benefits of employing drainage systems. For mines that have drainage systems in place, the cost of ventilation is significantly reduced because the drainage systems recover a significant percentage of the associated methane. Use of methane drainage systems also helps reduce production costs, as there are typically fewer methane-related delays at mines that employ drainage systems (Kim and Mutmansky, 1990). Today, methane drainage is a proven technology and much of the gas that is recovered can be used in various applications.

While drainage systems are currently used primarily for economic and safety reasons to ensure that methane concentrations remain below acceptable levels, these systems recover methane that also can be employed as an energy source. The quantity and quality of the methane recovered will vary according to the method used. The quality of the recovered methane is measured by its heating value. Pure methane has a heating value of about 1000 British Thermal Units per cubic foot (Btu/cf), while a mixture of 50 percent methane and 50 percent air has a heating value of approximately 500 Btu/cf.

Drainage methods include vertical wells (vertical pre-mine), gob wells (vertical gob), longhole horizontal boreholes, and horizontal and cross-measure boreholes. The preferred recovery method will depend, in part, on mining methods and on how the methane will be used. In some cases, an integrated approach using a combination of the above drainage methods will lead to the highest recovery of methane. The key features of the methane recovery methods are discussed in more detail below.

Vertical Pre-Mining Wells

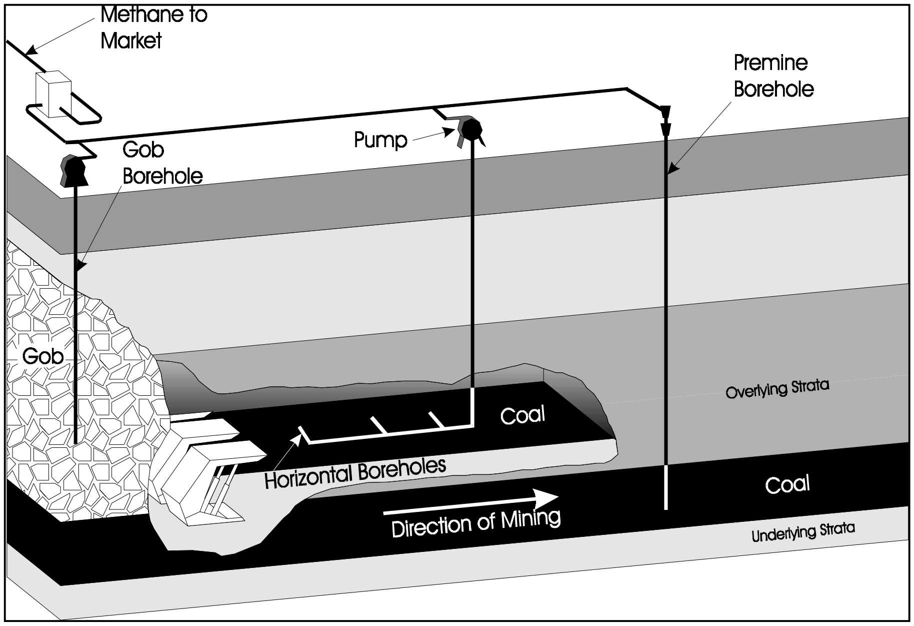
Vertical pre-mining wells are the optimal method for recovering high quality gas from the coal seam and the surrounding strata before mining operations begin. Pre-mine drainage ensures that the recovered methane will not be contaminated with ventilation air from mine working areas. Similar in design to conventional oil and gas wells, vertical wells can be drilled into the coal seam several years in advance of mining. Vertical wells, which may require hydraulic or nitrogen fracturing of the coal seam to activate the flow of methane, typically produce gas of over 90 percent purity. However, these wells may produce large quantities of water and small volumes of methane during the first several months they are in operation. As this water is removed and the pressure in the coal seam is lowered, methane production increases.

The total amount of methane recovered using vertical pre-drainage will depend on site-specific conditions and on the number of years the wells are drilled prior to the start of mining. Recovery of from 50 to over 70 percent of the methane that would otherwise be emitted during mining operations is likely for operations in which vertical degasification wells are drilled more than 10 years in advance of mining. Although not previously used widely in the coal mining industry, vertical wells are increasing in popularity within the coal industry, and are used by numerous stand-alone operations[5] that produce methane from coal seams for sale to natural gas pipelines. In some very low permeability coal seams, vertical wells may not be a cost-effective technology due to limited methane flow. Vertical wells, however, will likely continue to be a viable recovery technology for most underground mines.

Eight underground mines in the U.S. currently use vertical pre-mining wells. A majority of these mines already recover methane for pipeline sales (see section on existing methane recovery projects). Figure 2-3 illustrates a vertical pre-mine well.

[5] The term "stand-alone" refers to coalbed methane operations that recover methane for its own economic value. In most cases, these operations recover methane from deep and gassy coal seams that are not likely to be mined in the near future.

Figure 2-3: Vertical Pre-Mining Gob, and Horizontal Boreholes



Gob Wells

Gob wells are drilled from the surface to a point 10 to 50 feet above the target seam prior to mining. As mining advances under the well, the methane-charged strata that surround the well fracture. Relaxation and collapse of strata surrounding the coal seam creates a fractured zone known as the "gob" area, which is a significant source of methane. Methane emitted from the gob flows into the gob well and up to the surface. A vacuum is frequently used on the gob wells to prevent methane from entering mine working areas.

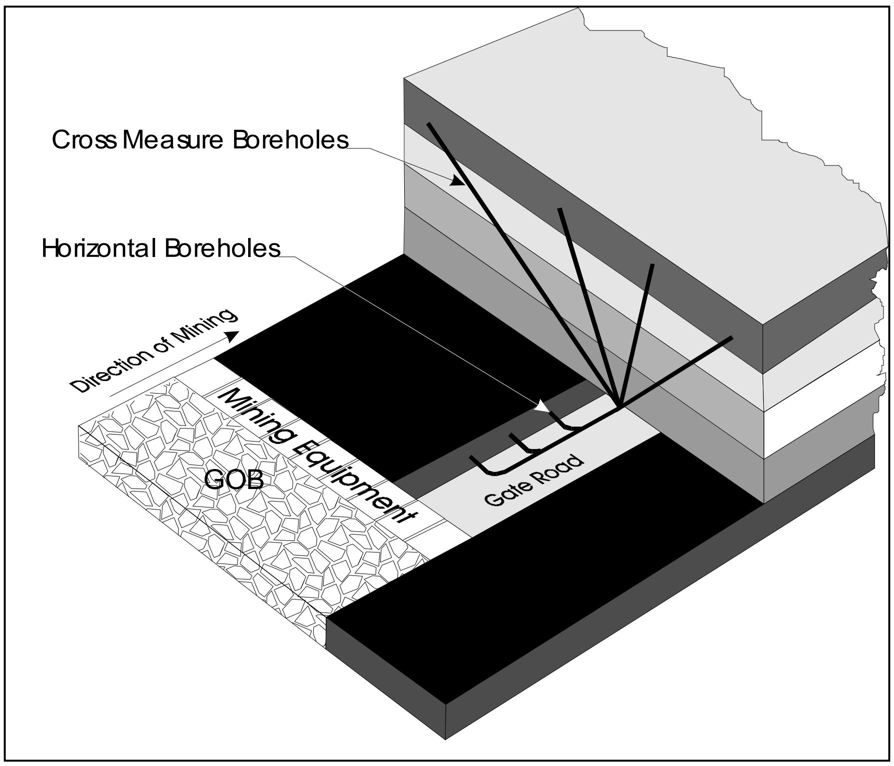
Initially, gob wells produce nearly pure methane. Over time, however, additional amounts of mine air can flow into the gob area and dilute the methane. The heating value of "gob gas" normally ranges between 300 and 800 Btu/cf. In some cases, it is possible to maintain nearly pure methane production from gob wells through careful monitoring and management. Jim Walter Resources, CONSOL, and Peabody are all using techniques for producing high-quality gas from gob wells. Gas production rates from gob wells can be very high, especially immediately following the fracturing of the strata as mining advances under the well. Jim Walter Resources reports that gob wells initially produce at rates in excess of two million cubic feet per day. Over time, production rates typically decline until a relatively stable rate is achieved, typically in the range of 100 mcf/d. Depending on the number and spacing of the wells, gob wells can recover an estimated 30 percent to over 50 percent of methane emissions associated with coal mining (USEPA, 1990).

Twenty one U.S. mines currently use surface gob wells to reduce methane levels in mine working areas. Most mines release methane drained from gob wells into the atmosphere. Figure 2-3 illustrates a vertical gob well.

Horizontal Boreholes

Horizontal boreholes are drilled inside the mine (as opposed to from the surface) and they drain methane from the unmined areas of the coal seam, or from blocked out longwall panels shortly before mining takes place. These boreholes are typically 400 to 800 feet in length. Several hundred boreholes may be drilled within a single mine and connected to an in-mine vacuum piping system, which transports the methane out of the mine and to the surface. Most often, horizontal boreholes are used for short-term methane emissions relief during mining. Because methane drainage only occurs from the mined coal seam (and not from the surrounding strata), the recovery efficiency of this technique is low -- approximately 10 to 18 percent of methane that would otherwise be emitted (USEPA, 1990). However, this methane typically can have a heating value of over 950 Btu/cf (USEPA, 1991). Approximately 12 underground mines in the U.S. currently use this technique to reduce the quantity of methane in mine working areas. Figures 2-3 and 2-4 illustrate horizontal boreholes.

Figure 2-4: Horizontal and Cross-Measure Boreholes



Longhole Horizontal Boreholes

Like horizontal boreholes, longhole horizontal boreholes are drilled from inside the mine in advance of mining. They are greater than 1000 feet in length and are drilled in unmined seams using directional drilling techniques. Longhole horizontal boreholes produce nearly pure methane with a recovery efficiency of about 50% and therefore can be used when high quality gas is desired. This technique is most effective for gassy, low permeability coal seams that require long diffusion periods. Both West Elk Mine in Colorado and San Juan South Mine in New Mexico have employed longhole horizontal boreholes in their drainage programs.

Cross-Measure Boreholes

Cross-measure boreholes degasify the overlying and underlying rock strata surrounding the target coal seam. These boreholes are drilled inside the mine and they drain methane with a heating value similar to that of gob wells. Cross-measure boreholes have been used extensively in Europe and Asia but are not widely used in the United States where surface gob wells are preferred. West Elk Mine in Colorado has employed cross-measured boreholes in the past. Figure 2-4 illustrates cross-measure boreholes.

Table 2-1
Summary of Drainage Methods

Method	Description	Gas Quality	Drainage Efficiency[a]	Current Use in U.S. Coal Mines[b]
Vertical Pre-Mine Wells	Drilled from surface to coal seam months or years in advance of mining.	Produces nearly pure methane.	up to 70%	Used by 8 mines.
Gob Wells	Drilled from surface to a few feet above coal seam just prior to mining.	Produces methane that is sometimes contaminated with mine air.	up to 50%	Used by 21 mines.
Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam shortly prior to mining.	Produces nearly pure methane.	up to 20%	Used by 12 mines.
Longhole Horizontal Boreholes	Drilled from inside the mine to degasify the coal seam shortly prior to mining.	Produces nearly pure methane.	up to 50%	Used by at least 2 mines.
Cross-measure Boreholes	Drilled from inside the mine to degasify surrounding rock strata shortly prior to mining.	Produces methane that is sometimes contaminated with mine air.	Up to 20%	Not widely used in the U.S.[c]

Source: USEPA (1993b) & USEPA (2003a)

[a] Percent of total methane liberated that is drained.

[b] Accurate only at the time of publication of this report, may vary often as mining progresses.

[c] Used at West Elk Mine at one time.

Utilization Options

Once recovered, coal mine methane is an energy source available for many different applications. Potential utilization options are pipeline injection, electricity generation, and direct use in on-site prep-plants or to fuel mine vehicles, or at nearby industrial or institutional facilities. Following is a discussion of various utilization methods. Table 2-2 shows the recovery methods that may be employed for each utilization option.

Table 2-2
Utilization Options for Coalbed Methane

Utilization Options	Range of Btu Quality (Btu/cf)	Recovery Method
Pipeline Injection Power Generation Local Use (at on-site coal prep plant or to fuel mine vehicles, or at nearby industrial or institutional facilities)	> 950	Vertical Wells (Pre-mining degasification)
Pipeline Injection – requires: (1) maintaining pipeline quality, or (2) gas enrichment Power Generation Local Use	300 to 950	Gob Wells
Pipeline Injection Power Generation Local Use	up to 950	In-Mine Boreholes
Use ventilation air methane as combustion air in gas-fired IC engines, gas turbines or coal-fired boilers; thermal oxidation; catalytic reactors; VOC concentrators; lean fuel gas turbines	1 to 20	Ventilation Air

Sources: USEPA (1990); USEPA (1991); USEPA (2003a)

Pipeline Injection

Methane liberated during coal mining may be recovered and collected for sale to pipeline companies. The key issues that will determine project feasibility are: 1) whether the recovered gas can meet pipeline quality standards; and 2) whether the costs of production, processing, compression and transportation are competitive with other gas sources.

U.S. experience demonstrates that selling recovered methane to a pipeline can be profitable for mining companies and is by far the most popular use method. As shown in Table 2-3, 10 of the profiled mines currently sell methane from their drainage systems to local pipeline companies. Chapter 3 contains additional information on these projects.

Technical Feasibility

The primary technical consideration involved in collecting coal mine methane for pipeline sales is that the recovered methane must meet the standards for "pipeline quality" gas. First, it must have a methane concentration of at least 95 percent and contain no more than a 2 percent concentration of gases that do not burn (i.e., carbon dioxide, nitrogen, helium). Additionally, any non-methane hydrocarbons are usually removed from the gas stream for other uses. Hydrogen sulfide (which mixes with water to make sulfuric acid) and hydrogen (which makes pipes brittle) must also be removed before the gas is introduced into the pipeline system. Finally, any water or sand produced with the gas must be removed to prevent damage to the system. While coalbed methane requires water removal, it is often free of hydrogen sulfide and other impurities typically found in natural gas.

With proper recovery and treatment, coalbed methane can meet the requirements for pipeline quality gas.

Table 2-3
Current Coal Mine Methane Pipeline Projects at Profiled Mines

Mining Company	Number of Active Mines	State
Jim Walter Resources	3	Alabama
U.S. Steel Mining	2	Alabama, West Virginia
Drummond Coal	1	Alabama
Consolidation Coal Company	1	West Virginia/Pennsylvania*
Eastern Associated Coal (Peabody)	1	West Virginia
CONSOL Coal Group	2	Virginia

* While the main entries for this mine and two abandoned mines (which are part of a single methane recovery project) are located in West Virginia, significant portions of the mines extend into Pennsylvania, and most of the gas production is from Pennsylvania.

Vertical degas wells are the preferred recovery method for producing pipeline quality methane from coal seams because pre-mining drainage ensures that the recovered methane is not contaminated with ventilation air from the working areas of the mine. Gob wells, in contrast, generally do not produce pipeline quality gas as the methane is frequently mixed with ventilation air. In certain cases, however, it is possible to maintain a higher and more consistent gas quality through careful monitoring and adjustment of the vacuum pressure in gob wells.

It is also possible to enrich gob gas to pipeline quality by using technologies that separate methane from carbon dioxide, oxygen, and/or nitrogen. Several technologies for separating methane are under development and may prove to be economically attractive and technically feasible with additional research (USEPA Technical Option Series). One such project currently operating is at the Blue Creek #4, #5, and #7 mines operated by JWR where a cryogenic gas processing unit was installed in 2000 to upgrade medium-quality gas, recovered from gob wells, to pipeline quality gas. Pressure swing adsorption is also being utilized.

Another option for improving the quality of mine gas is blending, which is the mixing of lower Btu gas with higher Btu gas whose heating value exceeds pipeline requirements. As a result of blending, the Btu content of the overall mixture can meet acceptable levels for pipeline injection. For example, CONSOL is blending gob gas recovered from the VP #8 and Buchanan mines in Virginia with coalbed methane production for pipeline injection.

Horizontal boreholes and longhole horizontal boreholes also can produce pipeline quality gas when the integrity of the in-mine piping system is closely monitored. However, the amount of methane produced from these methods is sometimes not large enough to warrant investments in the necessary surface facilities. In cases where mines are developing utilization strategies for larger amounts of gas recovered from vertical or gob wells, it may be possible to use the gas recovered from in-mine boreholes to supplement production.

Profitability

The overall profitability of recovering methane for pipeline injection will depend on a number of factors. These factors include the amount and quality of methane recovered (as discussed above), the capital and operating costs for wells, water disposal, compression and gathering systems, and, most importantly, the price at which the recovered gas may be sold.

The costs for disposal of production water from vertical wells may be a significant factor in determining the economic viability of a project, as discussed later in this chapter ("Production Characteristics of Coalbed Methane Wells"). The cost of gas gathering lines is another consideration. Because costs for laying gathering lines are high, proximity to existing commercial pipelines is a significant factor in determining the economic viability of a coalbed methane project. Most coal mines are located within 20 miles of a commercial pipeline (See Chapter 6). However, in some cases, existing pipelines may have limited capacity for transporting additional gas supplies. Costs for laying gathering lines vary widely depending, in part, on terrain. The hilly and mountainous terrain in many mining areas increases the difficulty, and thus the cost, of installing gathering lines.

Another determinant of the overall profitability of a pipeline injection project is a mine's ability to find a purchaser for its recovered gas. A methane recovery project will also need to demonstrate that its recovered methane is of the requisite pipeline quality.

Power Generation

Coalbed methane may also be used as a fuel for power generation. Unlike pipeline injection, power generation does not require pipeline quality methane. Gas turbines can generate electricity using methane that has a heat content of 350 Btu/cf. Mines can use electricity generated from recovered methane to meet their own on-site electricity requirements and can sell electricity generated in excess of on-site needs to utilities. An example is an 88 MW power generation station developed by CONSOL Energy and Allegheny Energy, placed near the VP #8 and Buchanan mines, fueled by coalbed methane and coal mine methane. Power generated is sold to the competitive wholesale market. The 88 MW project, though, is currently world's largest CMM-fired power plant. More typical are projects in the 1-10 MW range, and there is currently a 1.2 MW project using internal combustion engines at the Federal No. 2 Mine in West Virginia. In addition to the two US projects, additional power generation projects are reported to be operating at coal mines in China, Australia, UK and Germany.

Technical Feasibility

A methane/air mixture with a heating value of at least 350 Btu/cf is a suitable gaseous fuel for electricity generation. Accordingly, vertical degas wells, gob wells, and in-mine boreholes are all acceptable methods of recovering methane for generating power. Gas turbines, internal combustion (IC) engines, and boiler/steam turbines can all be adapted to generate electricity from coalbed methane. Fuel cells may also prove to be a promising option and are currently being tested at the Nelms Portal Mine in Ohio where a 250 kW Direct FuelCell®, manufactured by FuelCell Energy, Inc., will be set up to deliver power to the local utility. This project is being cost-shared by the Department of Energy.

Currently, the most likely generator choice for a coalbed methane project would be either a gas turbine or an IC engine. Boiler/steam turbines are generally not cost effective in sizes below 30 MW, while gas turbines are not the optimal choice for projects requiring 1.5 MW or less. However, when used in the right applications gas turbines are smaller and lighter than IC engines and historically have had lower operation and maintenance costs.

While maintaining pipeline quality gas output from gob wells can be difficult, the heating value of gob gas is generally compatible with the combustion needs of gas turbines. One potential problem with using gob gas is that production, methane concentration, and rate of flow are generally not predictable; wide variations in the Btu content of the fuel may create operating difficulties. Equipment for blending the air and methane may be needed to ensure that variations in the heating value of the fuel remain within an acceptable range -- approximately ten percent allowable variability for gas turbines.

A potential advantage of using vertical pre-mine wells as the recovery method for power generation is that the quantity and quality of methane produced is more consistent than that of gob wells. Thus, problems stemming from variations in the heating value of the fuel would be minimized where vertical wells are employed. Another option is to blend high quality gas from vertical wells with lower quality gas from gob wells to ensure consistent quality. Horizontal boreholes also can produce gas of consistently high quality. The limited quantity of gas produced by this method would likely need to be supplemented by larger quantities of methane from vertical or gob wells, however.

The level of electric capacity that may be generated depends on the amount of methane recovered and the "heat rate" (i.e., Btu to kWh conversion) of the generator. For example, simple cycle gas turbines typically have heat rates in the range of 10,000 Btu/kWh, while combined cycle gas turbines could have heat rates of 7,000 Btu/kWh. Assuming a conservative heat rate of 11,000 Btu/kWh and assuming that mines could recover 35 percent of total emissions, the level of electric capacity that could be sustained by the top twenty methane-emitting mines would likely exceed 10 MW per mine.

Profitability: Power Generation for On-Site Use

Given their large energy requirements, coal mines may realize significant economic savings by generating power from recovered methane. Nearly every piece of equipment in an underground mine operates on electricity, including mining machines, conveyor belts, ventilation fans, and elevators. Much of the equipment at typical mines is operated 250 days a year, two shifts per day. Ventilation systems, however, must run 24 hours a day, 365 days a year, and they demand a considerable amount of electricity -- up to 60 percent of the mine's total needs (USBM, 1992).

A mine's total electricity needs can exceed 24 kWh per ton of coal mined. Since many the largest underground mines in the U.S. produce more than 3 million tons of coal annually, they may purchase over 72 million kWh of electricity annually. At average industrial electricity rates of five cents per kWh, a mine's electricity bill can exceed several million dollars a year.

Coal preparation plants, which are frequently located near large mines, also consume a great deal of energy. Preparation involves crushing, cleaning, and drying the coal before its final sale. Coal drying operations require thermal energy, which could be generated by a turbine or engine in a cogeneration cycle. Coal preparation generally requires an additional 6 kWh per ton of coal (ICF Resources, 1990a). CONSOL currently recovers approximately 1.5 mmcf/d from the VP #8 and Buchanan mines for use in their thermal dryer.

Among the main factors in determining the economic viability of generating power for on-site use are the total amount and flow of the methane recovered, the capital costs of the generator, the expected lifetime of the project, and the price the mine pays for the electricity it uses. A mine would need to be fairly large to recover an amount of methane that would justify the capital expenditures for a generator and other equipment needed for utilizing power on-site. Moreover, because the $/kW capital cost of a generator is relatively high in terms of the overall economics of a coalbed methane power project, the mine would need to generate power for several years in order to justify the capital investment. A final economic consideration is the cost of back-up power, which is typically supplied by a utility and is essential for mining operations given their safety considerations.

Profitability: Off-Site Sale to a Utility

Large and gassy coal mines may be able to generate electric power from recovered methane in excess of their own power requirements. In such cases, a mine may be able to profit from selling power to a nearby utility. Additionally, under some circumstances, a mine might arrange to sell electricity to a utility, but continue to purchase electricity from the utility for its own on-site use. The economic feasibility of selling power off-site would depend on the amount of electricity that could be generated, the incremental costs of selling power to a utility, and the price received for the electricity.

If a mine is generating power to meet its own electricity needs, the incremental costs of selling excess power off-site are relatively low. Normally, a coal mine already has a large transmission line running from a main transmission line to the mine substation. In most cases, this same line could be used to transmit power from the mine back to the utility. For some mines, an interconnection facility or line upgrades may be needed to feed this additional power into the main line.

Ventilation Air Methane Use Technologies

Ventilation air methane (VAM) is now recognized as an unused source of energy and a potent atmospheric greenhouse gas (GHG). A host of recently introduced technologies can reduce ventilation air methane emissions, while harnessing methane's energy, and can offer significant benefits to the world community.

USEPA (2000) identified two technologies for destroying or beneficially using the methane contained in ventilation air: the VOCSIDIZER,[6] a thermal flow-reversal reactor developed by MEGTEC Systems (De Pere, Wisconsin, United States), and a catalytic flow-reversal reactor developed expressly for mine ventilation air by Canadian Mineral and Energy Technologies (CANMET—Varennes, Quebec, Canada). Both technologies employ similar principles to oxidize methane contained in mine ventilation airflows. Based on laboratory and field experience, both units can sustain operation (i.e., can maintain oxidation) with ventilation air having uniform methane concentrations down to approximately 0.1 percent. For practical field applications where methane concentrations are likely to vary over time, however, this analysis assumes that a practical average lower concentration limit at which oxidizers will function reliably is 1.5 percent.

In addition, a variety of other technologies such as boilers, engines, and turbines may use ventilation airflows as combustion air. At least two other technology families may also prove to be viable candidates for beneficially using VAM. These are VOC concentrators and new lean fuel gas turbines.

[6] VOCSIDIZER is a registered trademark of MEGTEC Systems.

Thermal Flow Reversal Reactor

Figure 2.5 shows a schematic of the Thermal Flow Reversal Reactor (TFRR). The equipment consists of a bed of silica gravel or ceramic heat-exchange medium with a set of electric heating elements in the center. The TFRR process employs the principle of regenerative heat exchange between a gas and a solid bed of heat-exchange medium. To start the operation, electric heating elements preheat the middle of the bed to the temperature required to initiate methane oxidation (above 1,000°C [1,832°F]) or hotter. Ventilation air at ambient temperature enters and flows through the reactor in one direction and its temperature increases until oxidation of the methane takes place near the center of the bed.

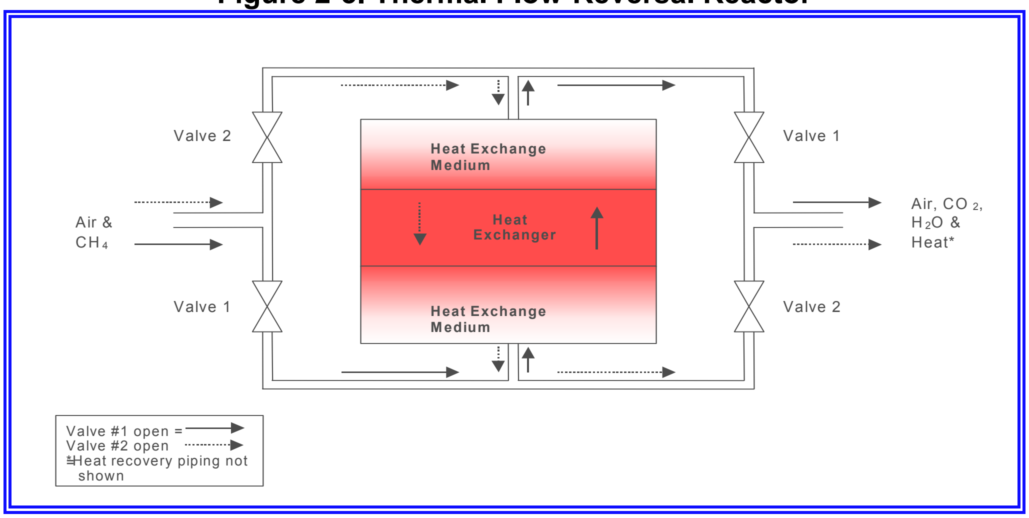
The hot products of oxidation continue through the bed, losing heat to the far side of the bed in the process. When the far side of the bed is sufficiently hot, the reactor automatically reverses the direction of ventilation airflow. The ventilation air now enters the far (hot) side of the bed, where it encounters auto-oxidation temperatures near the center of the bed and then oxidizes. The hot gases again transfer heat to the near (cold) side of the bed and exit the reactor. Then, the process again reverses.

TFRR units are effectively employed worldwide to oxidize industrial VOC streams. Recently, their ability to oxidize VAM has been demonstrated in the field.

Catalytic Flow Reversal Reactor

Catalytic flow reversal reactors adapt the thermal flow reversal technology described above by including a catalyst to reduce the auto-oxidation temperature of methane by several hundred degrees Celsius (to as low as 350°C [662°F]). CANMET has demonstrated this system in pilot plants and is now in the process of licensing Neill and Gunter of Dartmouth, Nova Scotia, to commercialize the design (under the name VAMOX).

Figure 2-5. Thermal Flow-Reversal Reactor



CANMET is also studying energy recovery options for profitable turbine electricity generation. Injecting a small amount of methane (gob gas or other source) increases the methane concentration in ventilation air can make the turbine function more efficiently. Waste heat from the oxidizer is also used to pre-heat the compressed air before it enters the expansion side of the gas turbine.

Energy Conversion from a Flow-Reversal Reactor

There are several methods of converting the heat of oxidation from a flow-reversal reactor to electric power, which is the most marketable form of energy in most locations. The two methods being studied by MEGTEC and CANMET are:

- *Use water as a working fluid.* Pressurize the water and force it through an air-to-water heat exchanger in a section of the reactor that will provide a non-destructive temperature environment (below 800°C [1472°F]). Flash the hot pressurized water to steam and use the steam to drive a steam turbine-generator. If a market for steam or hot water is available, send exhausted steam to that market. If none is available, condense the steam and return the water to the pump to repeat the process.
- *Use air as a working fluid.* Pressurize ventilation air or ambient air and send it through an air-to-air heat exchanger that is embedded in a section of the reactor that stays below 800°C (1472°F). Direct the compressed hot air through a gas turbine-generator. If gob gas is available, use it to raise the temperature of the working fluid to more nearly match the design temperature of the turbine inlet. Use the turbine exhaust for cogeneration, if thermal markets are available.

Since affordable heat exchanger temperature limits are below those used in modern prime movers, efficiencies for both of the energy conversion strategies listed above will be fairly modest. The use of a gas turbine, the second method listed, is the energy conversion technology assumed for the cost estimates in this report. At a VAM concentration of 0.5 percent one vendor expects an overall plant efficiency in the neighborhood of 17 percent after accounting for power allocated to drive the fans that force ventilation air through the reactor.

Other Technologies

USEPA has also identified other technologies that may prove able to play a role in and enhance opportunities for VAM oxidation projects. These are briefly described below.

Concentrators

Volatile organic compound (VOC) concentrators offer another possible economical option for application to VAM. During the past 10 years the use of such units to raise the concentration of VOCs in industrial-process air exhaust streams that are sent to VOC oxidizers has increased. Smaller oxidizer units are now used to treat these exhaust streams, which in turn has reduced capital and operating costs for the oxidizer systems. Ventilation air typically contains about 0.5 percent methane concentration by volume. Conceivably, a concentrator might be capable of increasing the methane concentration in ventilation airflows to about 20 percent. The highly reduced gas volume with a higher concentration of methane might serve beneficially as a fuel in a gas turbine, reciprocating engine, etc. Concentrators also may prove effective in raising the methane concentration of very dilute VAM flows to levels that will support oxidation in a TFRR or CFRR.

Lean Fuel Gas Turbines

A number of engineering teams are striving to modify selected gas turbine models to operate directly on VAM or on VAM that has been enhanced with more concentrated fuels, including concentrated VAM (see “Concentrator” section above) or gob gas. These efforts include:

- ***Carbureted gas turbine.*** A carbureted gas turbine (CGT) is a gas turbine in which the fuel enters as a homogeneous mixture via the air inlet to an aspirated turbine. It requires a fuel/air mixture of 1.6 percent by volume, so most VAM sources would require enrichment. Combustion takes place in an external combustor where the reaction is at a lower temperature (1200°C [2192°F]) than for a normal turbine thus eliminating any NOx emissions. Energy Developments Limited (EDL) of Australia is testing the CGT on ventilation air at the Appin coal mine in New South Wales, Australia.

- ***Lean-fueled turbine with catalytic combustor.*** CSIRO Exploration & Mining of Australia, a government research organization, is developing a catalytic combustion gas turbine (CCGT) that can use methane in coal mine ventilation air. The CCGT technology being developed oxidizes VAM in conjunction with a catalyst. The turbine compresses a very lean fuel/air mixture and combusts it in a catalytic combustor. CSIRO hopes to operate the system on a 1.0 percent methane mixture to minimize supplemental fuel requirements.

- ***Lean-fueled catalytic microturbine.*** Two US companies, FlexEnergy and Capstone Turbine Corporation, are jointly developing a line of microturbines, starting at 30 kW that will operate on a methane-in-air mixture of 1.3 percent.

- ***Hybrid coal and VAM-fueled gas turbine.*** CSIRO is also developing an innovative system to oxidize and generate electricity with VAM in combination with waste coal. CSIRO is constructing a 1.2-MW pilot plant that cofires waste coal and VAM in a rotary kiln, captures the heat in a high-temperature air-to-air heat exchanger, and uses the clean, hot air to power a gas turbine. Depending on site needs and economic conditions, VAM can provide from about 15 to over 80 percent (assuming a VAM mixture of 1.0 percent) of the system’s fuel needs, while waste coal provides the remainder.

VAM Used as an Ancillary Fuel

VAM can also be used as an ancillary or supplemental fuel. Such technologies rely on a primary fuel other than VAM and are able to accept VAM as all or part of their combustion air to replace a small fraction of the primary fuel. The largest example of ancillary VAM use occurred at the Appin Colliery in Australia, where 54 one-MW Caterpillar engines used mine ventilation air containing VAM as combustion air. Similarly, the Australian utility, Powercoal, is installing a system to use VAM as combustion air for a large coal-fired steam power plant. In addition, the US Department of Energy funded a research project to use VAM in concentrations up to 0.5 percent as combustion air in a turbine manufactured by Solar. Even the CSIRO hybrid coal and VAM project described in the preceding paragraph falls in the category of ancillary VAM use when waste coal combustion is maximized and VAM use is limited to prescribed levels of combustion air.

Project Economics for Ventilation Air Methane Use Technologies

Many of the technologies for VAM use are still in the developmental stage, and cost information is still limited. The costs for simply using the VAM as combustion air either in reciprocating engines or turbines is negligible, the only costs being construction and operation of equipment to move the air to the generator sets. Additional maintenance of the engines or turbines may be necessary if excess moisture and dust are present in the mine ventilation air. Developers of the lean-burn turbines are reporting that they can produce 30-100 kW units for about $1,000-2,000 per kW while commercial production of larger scale units (200 kW – 2 MW) would drive down the costs significantly to $600-$1,000 per kW.

The majority of economic data available is for the flow reversal reactors. Field-scale and bench-scale tests of the MEGTEC TFRR and the Canmet CFRR, respectively, have provided more reliable cost data than other technologies. In 2003, EPA released the report, "Assessment of the Worldwide Potential for Oxidizing Coal Mine Ventilation Air Methane," the most comprehensive assessment to date of the marginal abatement costs of VAM use technologies. With methane abatement costs at $3.00 per tonne of CO_2e, VAM-derived power projects in the US could theoretically create 457 MW of net useable capacity. If the equipment value for each project were rounded to $10 million, the total equipment market estimate for the US would be over $1.2 billion. Finally, the annual revenues that could accrue from such power sales in the country could amount to over $120 million (USEPA 2003b).

Local Use

In addition to pipeline injection, power generation, and ventilation air methane use, coal mine methane may be used as a fuel in on-site preparation plants or vehicle refueling stations, or it can be transported to a nearby coal-fired boiler or other industrial or institutional facilities for direct use.

Nearly all large underground coal mines have preparation plants located nearby. Mines have traditionally used their own coal to fuel these plants, but there is the potential to use recovered methane instead. Currently, CONSOL uses recovered methane to fuel the thermal dryer in one of its preparation plants. In Poland, several coal mines have used recovered methane to fuel their coal drying plants.

Another option for on-site methane use may be as a fuel for mine vehicles. Natural gas is much cheaper and cleaner than diesel fuel or gasoline, and internal combustion engines burn it more efficiently.

In addition to on-site methane use, selling recovered methane to a nearby industrial or institutional facility may be a promising option for some mines. An ideal gas customer would be located near the coal mine (within five miles) and would have a continuous demand for gaseous fuel. Coal mine methane could be used to fuel a cogeneration system, to fire boilers or chillers, or to provide space heating. In some cases, local communities may find that the availability of an inexpensive fuel source from their local mine can help them attract industry and generate additional jobs.

Additionally, there are numerous international examples of mine gas being used for industrial purposes. For example, in Ukraine and Russia, recovered methane is used in coal-fired boilers located at the mine-site. In the Czech Republic, coal mine methane is used in nearby metallurgical plants. In Poland, recovered methane is used as a feed-stock fuel in a chemical plant. In China, methane has been used in carbon black plants.

Finally, co-firing methane with coal in a boiler is another potential utilization option, particularly for mines that are located in close proximity to a power plant. A few of the mines profiled in this report are located within a few miles of a coal-fired plant (for example, Robinson Run is located about three miles from Allegheny Power's Harrison Plant).

Flaring

Environmentally, flaring methane is nearly as beneficial as utilizing the methane as fuel, since flaring changes the majority of the methane to carbon dioxide. Emitting carbon dioxide is much less harmful in terms of the impact on global warming than is the direct emission of methane. For purposes of greenhouse gas reductions, the value of recovering one ton of methane and using it to generate energy (in lieu of burning natural gas from a traditional source) is equivalent to a 21 ton reduction in carbon dioxide emissions. If mine emissions are flared without using the combustion to displace energy from other sources, flaring yields greenhouse gas reductions equal to 87.5% of those achievable through recovery and use (Lewin, 1997).

Although there are flares at a closed mine in the U.S., to date, flaring has not been implemented at active mines in the U.S. The principal concern expressed by the coal industry is that it is not safe to pipe the gas to a point where it would be flared because of the potential for the flame to propagate back down to the mine and to cause an underground explosion (Lewin, 1995). If agreement on the safe practice of flaring methane recovered from coal mines is reached, flaring could become an additional option for mitigating methane emissions, however, the flaring option still requires acceptance of miners, MSHA, union parties, and mine owners. Through a series of reports, EPA has outlined the benefits of flaring and addressed these concerns by offering a conceptual flare design (US EPA, 1999).

Green Pricing Projects

With the advent of competition in the electric utility industry, utilities are recognizing the need to provide new services to the customers. One such service is "green pricing". Under green pricing, customers have a choice regarding the type of electricity they choose to purchase. Customers could choose conventional power, which they could purchase at a standard rate, or they could purchase green power at a slightly higher rate. As part of the green pricing program, for every customer who commits to pay the higher rate, the utility pledges to buy enough "environmentally friendly" energy to completely offset the customer's share of conventionally generated electricity. In 2000, the State of Pennsylvania Public Utility Commissions included CMM as a renewable energy source as part of their green pricing program.

Barriers to the Recovery and Use of Coal Mine Methane

While a number of U.S. coal mines are already selling recovered methane to pipelines, numerous seemingly profitable projects have not been undertaken at other mines. Currently, a number of problems and disincentives exist that distort the economics of coal mine methane projects, with the result that many potentially profitable investments are not being developed. These obstacles include unresolved legal issues concerning ownership of the coalbed methane resource, power prices and pipeline capacity constraints, among other technical challenges.

Ownership of Coalbed Methane

Unresolved legal issues concerning the ownership of coalbed methane resources have constituted one of the most significant barriers to coalbed methane recovery. Ambiguity in certain state legal systems provides a disincentive for investment in coalbed methane projects because of the uncertainties as to which parties may demand compensation for development of the resource. Although ownership legislation has improved the investment climate, coalbed methane industry forums have still identified ownership issues as serious obstacles to methane recovery. Courts are being called upon on a case-by-case basis to determine the ownership of coalbed methane in situations where mining and mineral rights have been severed from land ownership. The issue is simply whether the owner of the rights to the coal and/or gas also owns the coalbed methane rights. Resolution can happen only after all the facts are considered in each case.

Power Prices

Another factor contributing to the slow development of CMM-fueled power generation is the low prices of electricity in many U.S. coal producing regions. When comparing the economics of power generation to other alternatives, low electricity prices have resulted in power projects not being as attractive, regardless of the designated end-use for the power, whether it be on-site at the mine to offset electricity purchases, or to sell the power to the local utility.

Production Characteristics of Coalbed Methane Wells

Gas Production

Coalbed methane degasification wells have production characteristics that differ from conventional gas wells in a variety of respects. One important difference is the amount of control the developer has in terms of the gas flow. With conventional gas wells, the gas flow may be controlled, or completely halted, at the discretion of the operator. This provides the operator with flexibility as to when the gas is sold. Vertical pre-mine degasification wells can be controlled as their production is not directly related to mining activities. In-seam and gob wells, however, are not subject to the same control by virtue of their purpose. These wells are used primarily to drain a mine of methane for safety reasons. As such, the feasibility of turning off and on an in-seam or gob well depends on safety first and gas production second.

The production characteristics of coalbed methane wells present difficulties in the context of the natural gas and pipeline industries. Much of the consumer demand for natural gas is seasonal in nature. In addition, in situations of limited pipeline capacity, local pipelines may not be able to accept the gas supplied from coalbed methane projects on a continuous, uninterrupted basis. In particular, some areas of the Appalachian region have limited pipeline capacity. Storage of coalbed methane in depleted natural gas reservoirs or abandoned mines is an excellent means of overcoming problems related to fluctuations in demand or pipeline capacity. EPA has investigated the potential for storing methane recovered from active coal mines in nearby abandoned coal mines, concluding that if the abandoned mine were to meet certain criteria a project could be sustainable (USEPA, 1998).

Water Production

Another area in which technical challenges may arise is water disposal. In many instances, vertical coalbed methane wells will produce water from the coal seam and surrounding strata. Water is also produced during conventional mining operations, but some states have adopted separate regulations for water produced in association with coalbed methane operations and for water produced as a result of mining operations. For mines located near fresh water bodies or other vulnerable areas, surface water disposal may not be environmentally acceptable. Several alternative disposal and treatment methods are in use or under development, including deep well injection and other surface treatment approaches. These treatments may have higher costs associated with them, and in some cases additional research is necessary to address technical issues.

3. Overview of Existing Coal Mine Methane Projects

3. Overview of Existing Coal Mine Methane Projects

Coal mine methane recovery and use is a proven technology. This chapter discusses methane recovery and use projects at 10 mines profiled in Chapter 6. In 2001, total methane sales from coal mine methane projects at profiled mines was nearly 40 billion cubic feet, which is the equivalent of nearly 16 million tons of carbon dioxide.[7] At the current wellhead gas price of roughly $4 per thousand cubic feet, and assuming that all recovered gas was sold to a pipeline, these projects collectively will have grossed approximately $160 million dollars in annual revenues. Additionally, by working to maximize the amount of gas recovered from their drainage systems, these projects have greatly reduced mine ventilation costs and have improved safety conditions for miners.

The projects in Alabama, Pennsylvania, Virginia, and West Virginia employ a variety of degasification techniques, including vertical wells (pre-mining degasification), gob wells, and in-mine boreholes. Regardless of the degasification system employed, all mines have been able to recover large quantities of gas suitable for use in various applications. Following is a brief overview of the existing projects, arranged by location. Table 3-1, at the end of this chapter, summarizes the major characteristics of the existing projects.

Alabama

Five mines in Alabama recover and sell methane: Blue Creek No. 4, Blue Creek No. 5, Blue Creek No. 7, Oak Grove and Shoal Creek. The Blue Creek No. 4, No. 5 and No. 7 mines are owned by Jim Walter Resources (JWR), while the Oak Grove Mine is owned by U.S. Steel Mining, and the Shoal Creek Mine is owned by Drummond Coal.

Jim Walter Resources (JWR)

Blue Creek No. 4, No. 5, and No. 7 Mines

Located in Jefferson and Tuscaloosa Counties, Alabama, the JWR mines are among the deepest and gassiest mines in the country. Opened in the early to mid-1970's, the mines cover an 80,000 acre area and have vertical shafts ranging from 1,300 to 2,100 feet in depth. The in-situ gas content of coal is about 500 to 600 cubic feet per ton and the total amount of methane liberated from these mines is estimated to be between 2,200 – 5,800 cubic feet per ton of coal produced.

JWR has been a leader in the development of coal mine methane recovery projects in the United States. The company's Blue Creek mines -- the Nos. 4, 5, and 7 mines -- are currently recovering and selling approximately 34 million cubic feet of gas per day (Alabama Oil & Gas, 2002). Methane is produced using three recovery methods: 1) vertical degasification (holes drilled from the surface into the virgin coalbed); 2) horizontal degasification (holes drilled in the coalbed from active workings inside the mine); and 3) gob degasification program (holes drilled from the surface into the caved area behind the longwall faces).

Since the late 1980s, JWR has been producing between 25 – 35 mmcf/d of methane. As of December 2001, there were 256 wells producing approximately 27 mmcf/d. The quantity of methane recovered in 2001 represents 45 percent of total methane liberated from the mines. Depending on the mine, recovery from vertical pre-mine wells in 2001 made up approximately 15 - 35 percent of production, while gob wells and in-mine boreholes made up the remaining 65 - 85 percent of production.

[7] Methane emissions may be converted to a measure equivalent to carbon dioxide, since methane is 21 times more potent than carbon dioxide over a 100 year time frame.

U.S. Steel Mining

Oak Grove Mine

U.S. Steel Mining's (USM's) Oak Grove Mine produces methane for pipeline sales. USM is a subsidiary of USX, Incorporated (formerly U.S. Steel Corporation). Oak Grove is located in the east-central portion of the Black Warrior Basin of Jefferson County, Alabama. The target seam for mining is the Blue Creek bed of the Mary Lee coal group. The coal is mined at a depth of approximately 1,150 feet.

The effectiveness of a large-scale pattern of stimulated vertical wells in reducing the gas content of a coalbed was first demonstrated at the Oak Grove Mine in 1977. This was the first large-scale coal seam degasification project in the United States using vertical wells, as well as one of the first coalbed methane production projects. After 10 years, the original wells had produced a total of 3.2 Bcf (billion cubic feet) of methane that will never need to be controlled in the underground mine environment. Most of the wells in the field, however, are well beyond the near-term mine plan. In 2001, 44 pre-drainages wells that are scheduled to be mined-through during the next few years produced nearly 3 mmcf/d. In addition to the vertical wells drilled in advance of mining, Oak Grove Mine also has utilized both horizontal and gob wells for methane drainage, primarily to increase the safety of the underground mine. Since 1997, as many as 15 gob and horizontal wells have been in production in a given year. In 2001, only two of these wells remained in production, producing 500 mcf/day.

Because the sole goal of other companies drilling in the Oak Grove Degasification Field is commercial methane production, rather than reducing emissions from future mining operations, most of the wells drilled since 1985 have been spaced on a 160-acre (or greater) pattern. While these wells do drain methane from the area to be mined, the wider well spacing does not drain the coal as effectively as would a true vertical pre-mine drainage program.

Drummond Coal

Shoal Creek Mine

Drummond Coal's Shoal Creek Mine began producing coal in 1994. The mine entry is located in the Oak Grove Field, but mining will progress into the White Oak Field. Currently, Shoal Creek is using vertical pre-mine, horizontal and gob wells to drain methane. The pre-mine wells in the White Oak Field are operated by SONAT Exploration Co., Taurus Exploration, Inc., Kukui Operating Co., and El Paso Production Co. Nearly 60 wells are located within the 5-year mine plan and produced about 3 mmcf of methane per day for pipeline sales in 2001. In 2000, the mine drilled its first two gob wells, which produced an average of 240 mcf/d in 2001.

Pennsylvania

There is one methane recovery and use project underway in Pennsylvania. The project involves three mines owned by Consolidation Coal Company. Because the main portals for these mines are in West Virginia, they are categorized as West Virginia mines in Chapter 6 (the individual mine profiles section of this document). However, significant sections of the mines extend into Pennsylvania, and the majority of the gas produced is from coal and strata in Pennsylvania, therefore this methane recovery and use project is classified as a Pennsylvania project. Of the three mines, two are abandoned; therefore this report will only focus on the active mine.

Consolidation Coal Company (a subsidiary of the CONSOL Energy)

Blacksville No. 2

CONSOL and CBE Inc. are undertaking a gas enrichment and sales project at the Blacksville No. 2 Mine. In 1997, CBE began selling enriched gas directly to the pipeline. The project captured as much as 4 mmcf/day from the mine, and removed carbon dioxide, oxygen and nitrogen from the gas using catalytic, amine and cryogenic processes respectively. Columbia Energy Services purchases the resulting pipeline-quality gas. The enrichment plant is able to process 5-6 mmcf/d of gas whose methane content (prior to enrichment) is about 80-85%. The project can be expanded to process 10-12 mmcf/d. Operational problems in 2000 and 2001 have kept the project from maintaining its maximum output. Since that time, CONSOL has assumed full responsibility for the project and expects to optimize the production.

Virginia

The commercial potential of coalbed methane recovery in Virginia has long been recognized, but complicated issues regarding gas ownership, as well as the lack of pipeline capacity in southwest Virginia, delayed commercial coalbed methane recovery in this area until the early 1990's. There are two methane recovery and use projects currently underway in Virginia. These projects are taking place at the Buchanan No. 1 and VP No. 8 mines. The CONSOL Coal Group owns both mines.

CONSOL

CONSOL recovers methane from two of the gassiest mines in the southwestern region of Virginia: Buchanan No. 1 and VP No. 8. One of these mines, VP No. 8 was born out of the consolidation of the VP No. 5 and VP No. 6 mines in 1994. CONSOL has operated the adjacent Buchanan No. 1 Mine since 1983. The company has developed extensive degasification programs on both their properties, and continues to invest in vertical pre-mine wells. Although more gas can be successfully drained if a vertical pre-mine well has been in place for a long period, CONSOL has been opting for an advance drainage time frame that adequately balances the risk of investing in a vertical pre-mine drainage system with that of the company's mining plans. Thus, the company uses a three to five year advance degasification program to the extent that this can be feasibly coordinated with the company's overall mining strategies.

Currently, CONSOL produces gas for pipeline sales, on site use, and power generation. The total methane drained at the two CONSOL Virginia mine properties totaled nearly 107 mmcf/d in 2000 and 2001 (Virginia, 2002). This number significantly exceeds ventilation emissions of 18 – 20 mmcf/d, which indicates that much of the produced gas comes from virgin coals that CONSOL may mine in the future, and/or that recovery efficiencies are higher than standard EPA assumptions.

Of the 107 mmcf/d of methane that CONSOL currently recovers, approximately 70 mmcf/d can be attributed to emissions reduction at the mines, with an additional 1.5 mmcf/d being used on-site in a thermal dryer. The remaining amount is sold to a pipeline and used in the 88 MW power plant. Of the total recovered methane, gob wells and in-mine horizontal boreholes account for approximately 69 percent of methane production at the mines. Vertical pre-mine wells that have been mined through and impact emissions reductions at the mines account for the remaining 31 percent. This production from the vertical wells represents only about one third of the total gas sales occurring in the coals being drained ahead of mining.

Buchanan No. 1 Mine

A deep and gassy mine, Buchanan No. 1 is actively mining at a depth of about 1,500 feet and has an in-situ gas content of about 600 cf/ton. Beginning in May 1995, Buchanan No. 1 began using recovered methane, instead of coal, as fuel in its thermal dryer. As of May 1997, the thermal dryer consumes approximately 1.5 mmcf/d, or 547.5 mmcf/year (CONSOL, 1997). In addition, over 7 mmcf/d was recovered from gob and horizontal wells at the mine in 2001.

VP No. 8 Mine

Gas sales started in May 1992 at a rate of 3 mmcf/d. Over the next twelve months, production had grown to more than 30 mmcf/d (about 11 Bcf per year). In 2001, gas sales exceeded 60 mmcf/d via three methods, vertical pre-drainage wells, horizontal boreholes, and gob wells. Additionally, CONSOL recovers methane from abandoned areas at the VP and Buchanan mines. Once a methane drainage program from an abandoned area is completed, that area is sealed and no further methane extraction takes place (CONSOL, 1997).

West Virginia

There are two methane recovery and use projects currently underway in West Virginia[8]. These projects are taking place at the Federal No. 2 and Pinnacle No. 50 mines. The Federal No. 2 Mine is owned by Peabody Coal and the Pinnacle No. 50 Mine is owned by U.S. Steel Mining.

Eastern Associated Coal (Peabody)

Federal No. 2 Mine

Federal No. 2 currently drains methane using vertical gob wells. The mine markets gas recovered from some higher quality gob wells to a natural gas pipeline. This gas project is a joint venture with Dominion Gas Company. Dominion recovered approximately 1 mmcf/d in 2000 and 2001. The project at Federal No. 2 continues to expand as more sealed longwall panels become available to drain.

Eastern Associated Coal and Northwest Fuel Development are involved in a Department of Energy funded effort to evaluate the use of an integrated power generation system comprised of IC engines and gas turbines (U.S.DOE, 2000). This combination of equipment will allow low quality and variable quality gob gas to be used as a fuel. The electricity produced will power CNG's existing coalbed methane pipeline injection operations at the mine site. A generation capacity of 1.2 MW is planned.

The Federal No. 2 power project will build upon an aggressive coalbed methane degasification and commercialization project that likely will involve in-seam horizontal boreholes, gob wells, and vertical pre-mine wells.

[8] Another project involving three West Virginia mines is discussed under the "Pennsylvania" section earlier in this chapter, for reasons explained in therein.

U.S. Steel Mining

Pinnacle No. 50 Mine

USM's Pinnacle No. 50 Mine, located in West Virginia, produces methane for pipeline sale. Currently, the mine sells recovered coal mine gas to a local pipeline company. Until recently, methane recovery in the area had been hindered by high road and location costs. As a result, CDX Gas, LLC now uses a unique horizontal borehole drainage system called the Z-Pinnate Horizontal Drilling and Completion technology. Under this dual system approach, a vertical well is drilled first and the target coal seam is cavitated. Then a horizontal hole is kicked off from a second well and intersects the cavity of the first well. The cavity acts as a down-hole water separator, retaining water while gas flows to the production well. Finally, a lateral well is drilled through the cavity along the coal seam for up to 4800 feet. When the drill is pulled back along this main branch, paired branches are drilled at 45 degrees to the main, yielding a “barbed” appearance from a plan view. This process continues back toward the production well, creating a series of barbed branches that CDX calls a “pinnate” drilling pattern. Four of these patterns can be drilled from a central well.

In 2000 and 2001, the Pinnacle Mine recovered and sold approximately 8 mmcf/d of gas from its pre-mine drainage wells. The mine benefited directly with emissions reductions of 3.5 and 5.5 mmcf/d, respectively, when they mined through the pre-drained regions. In addition, the mine uses gob vent boreholes to drain methane, but currently does not recover this gas.

Summary

Table 3-1 summarizes the methane recovery and use projects discussed in this chapter.

Table 3-1: Summary of Existing Methane Recovery and Use Projects

Mine Name	Mine Location (State)	Approximate Amount of Gas Used in 2001	Methane Use Option	Notes
Blue Creek No. 4 Blue Creek No. 5 Blue Creek No. 7	Alabama	27 mmcf/day	Pipeline Sales	The three mines collectively produced 34 mmcf/day of gas in 2001, but only 27 mmcf/d is credited to emissions avoided.
Oak Grove	Alabama	3 mmcf/day	Pipeline Sales	Most of the production in the Oak Grove Field is beyond the limits of the mine plan.
Shoal Creek	Alabama	7 mmcf/day	Pipeline Sales	Most of the production from the White Oak Field is outside the limits of the mine plan.
Buchanan No. 1 VP #8	Virginia	107 mmcf/day	Pipeline Sales On-Site Use Power Generation	These two mines collectively produced 107 mmcf/day of gas in 2001, of which 70 mmcfd contributes to emissions reduction at the mines. A small portion (1.5 mmcf/d) of the total gas production is used on-site in a thermal dryer.
Blacksville No. 1	Pennsylvania	4mmcf/day	Pipeline Sales	Gas is produced from two abandoned mines that are part of the project, but over 4 mmcf/d is from the active mine alone.
Federal No. 2	West Virginia	1 mmcf/day	Pipeline Sales, Power Generation (planned)	Project continues to expand as mine grows. A second project using methane to generate electricity is planned.
US Steel No. 50	West Virginia	8 mmcf/day	Pipeline Sales	A unique, horizontal pre-mine drainage program is utilized.
NA means not available [1]Unless otherwise specified [2]Mine not profiled in this report				

4. A Key to Evaluating Mine Profiles

4. A Key to Evaluating Mine Profiles

This report contains profiles of coal mines that are potential candidates for the development of methane recovery and use projects. Also included are mines that already have installed methane recovery and use systems. The mines that are profiled were selected primarily on the basis of their annual methane emissions from ventilation systems as recorded in a Mine Safety and Health Administration database (MSHA, 2002). While this report is thought to contain a comprehensive listing of the best candidates for cost-effective methane recovery projects, it is possible that some promising candidate mines have not yet been identified.

The mine profiles presented in this report are designed to assist interested parties in identifying mines that can sustain a profitable methane recovery and use project. Each mine profile is comprised of the following sections:

- geographic data,
- corporate information,
- mine address,
- general information,
- production, ventilation and drainage data,
- energy and environmental value of emission reductions,
- power generation potential,
- pipeline sales potential,
- other utilization possibilities,

The mine profiles are ordered alphabetically by state, then by mine name. Following this chapter are summary tables that list key data elements shown in the mine profiles. Summary Table 1 lists all profiled mines in alphabetical order. The individual mine profiles follow the summary tables.

Operating Status

Each mine's operating status as of December 2002 is listed at the top right-hand corner of each profile. The operating status may be listed as described below:

Active: These mines are currently producing coal.

Idle: A mine that is open but not currently producing coal.

The current operating status was determined by reviewing coal industry publications that track the production status of coal mines, and through discussions with MSHA district offices and sources in the coal industry. No closed or abandoned mines are included in this report.

Geographic Data

The first section of each profile gives the geographic location of the mine, including the state, county, coal basin where the mine is located, and the coalbed(s) from which it produces coal. The sources for this information were MSHA (2002) and the Keystone Coal Industry Manual (Keystone, 2002).

State: Mines included in this report are located in the following states -- Alabama, Colorado, Illinois, Indiana, Kentucky, New Mexico, Ohio, Pennsylvania, Utah, Virginia, or West Virginia. Summary Table 2 shows the mines listed by state.

County: A relatively small number of counties contain a majority of the gassy mines in the country. Summary Table 2 shows the mines listed by state and by county.

Coal Basin: Mines are located in one of five major coal producing regions: the Black Warrior Basin, the Central Appalachian Basin, the Northern Appalachian Basin, the Illinois Basin, or one of the "Western basins" (Canon City Field, Piceance Basin, Raton Mesa, or Uinta Basin), which are located in the states of Colorado, Utah and New Mexico. Major geological characteristics of coal seams, including methane content, sulfur content, depth, and permeability tend to vary by basin. Summary Table 3 lists the mines by basin and 2001 estimated specific emissions per ton of coal mined for each listed mine.

Coalbed: Substantial and detailed information has been published on the geological and mining characteristics of major coalbeds occurring in the U.S. Summary Table 4 lists mines according to the seam from which they produce their coal.

Corporate Information

Current Owner: Current owner refers to the mining company that owns the mine. Summary Table 5 lists mines by mining company. The sources for this information were the MSHA database and the Keystone Coal Industry Manual (Keystone, 2002).

Parent Company: Many coal companies are owned by a parent company. In addition to showing the coal companies, Summary Table 5 also shows the parent corporation of the mining company. This information was taken from Keystone (2002).

Previous Owner: The name of any previous mine owners is useful as some of the coal mines profiled here have had numerous owners. This information, along with the previous or alternate name of the mine, is based on previous editions of the Keystone Coal Industry Manual.

Previous or Alternate Name: Mines frequently undergo name changes, particularly when they are purchased by a new company. This section lists previous or alternate mine names.

Mine Address

This section includes the phone number and mailing address of the mine and a contact name. The principal source of this information was the Keystone Coal Industry Manual. The phone numbers and mailing addresses are believed to be current. The contact names, however, may be somewhat out of date because the most recent editions of the Keystone Coal Industry Manual have not included this information for all of the mines.

General Information

Number of Employees: This field shows the number of people employed by the mine, as reported in the Keystone Coal Industry Manual. The number of employees reflects the latest year for which data were available. In some cases, the data are from the early 1990's, because the number of employees at the mine was not included in more recent editions of the Keystone Coal Industry Manual. For mines that are categorized as closed, the profile lists the number of persons employed by the mine when it was operating.

Year of Initial Production: Year of initial production indicates the age of the mine, as reported in the Keystone Coal Industry Manual.

Life Expectancy Life expectancy can be an important factor in determining whether a mine is a good candidate for a methane recovery and use project. Information on life expectancy was collected from various Keystone Coal Industry Manuals. However, given the difficulty in predicting mine life this statistic is perhaps only marginally useful, and care should be exercised in basing decisions on this factor.

Prep Plant Located On Site: The profile indicates whether a preparation plant is located at the mine, based on the Keystone Coal Industry Manual's and *Coal* magazine's annual prep plant surveys. At the preparation plant, coal is crushed, cleaned and dried. Most large mines have a prep plant located within close proximity. In some cases, a prep plant will process coal not only from the on-site mine, but also from other nearby mines. Information regarding whether the mine has a prep plant, and the amount of coal processed, is of importance in determining the mine's total electricity and fuel demands.

Mining Method: Mines are classified as longwall or room-and-pillar, based on *Coal* magazine's annual longwall survey and on information in coal industry publications. The mining method used is important for several reasons. First, longwall mines tend to emit more methane than do room-and-pillar mines, as the longwall technique tends to cause a more extensive collapse of, and relaxation of the methane-rich strata surrounding the coal seam. Furthermore, longwall mining has higher up-front capital costs. Thus, a company is not likely to invest in a longwall at a mine that is not expected to have a fairly long life. Finally, while room-and-pillar mining is the more common method, the number of longwall mines is growing. In fact, the longwall technique seems to be the preferred mining method at the largest and gassiest mines. Summary Table 6 lists mines by mining method.

Primary Coal Use: Coal may be used for steam and/or metallurgical purposes. Steam coal is used by utilities to produce electricity, while metallurgical coal is used to produce coke. The primary coal use is based on information in the Keystone Coal Industry Manual. Summary Table 7 lists mines by primary coal use.

Btus/lb: Btus (British Thermal Units) per pound of coal produced indicates the heating value of the coal. This statistic, which was taken from the Keystone Coal Industry Manual, is used in comparing the energy value of the coal to the energy value of the methane recovered (see section on Environmental and Energy benefits below).

Production, Ventilation and Drainage Data

This section presents the quantity of methane emitted from, and the amount of coal produced by, the profiled mines for each of the years 1997 to 2001.

Coal Production: Most of the mines profiled in this report are large, with production exceeding one million tons per year. Annual coal production is an important factor in determining a mine's potential for profitable methane recovery. Generally, larger mines will be better candidates because of the potential for high methane production and because they are more likely to be able to finance the large capital investments required for a methane recovery and utilization project. Coal production was based primarily on annual Energy Information Administration (EIA) reports, but was supplemented with data from coal producing states. Summary Table 9 lists the coal mines by the amount of coal they produced in 2001.

Estimated Total Methane Liberated: Methane liberation is the total volume of methane that is removed from the mine by ventilation and drainage. Liberation differs from emissions in that the term emissions, as used in this report, refers to methane that is not used and is therefore emitted to the atmosphere. Estimated total methane liberated is the sum of "emissions from ventilation systems" and "estimated methane drained." For mines that do not use or sell any of their methane, estimated total methane liberated equals estimated methane emissions to the atmosphere. The volume of methane liberated is shown for the years 1997-2001. Summary Table 10 shows mines listed by their estimated total daily methane liberation for 2001.

Emissions from Ventilation Systems: Methane released to the atmosphere from ventilation systems is emitted in very low concentrations (typically less than one percent in air). MSHA field personnel test methane emissions rates at each coal mine on a quarterly basis. Testing is performed underground at the same location each time. However, MSHA does not necessarily conduct the tests at precise three-month intervals, nor are they always taken at the same time of day. The ventilation emissions data for a given year are therefore averages of the four quarterly tests, and are accurate to the extent that the data collected at those four times are representative of actual emissions. Summary Table 11 lists the mines by their 2001 ventilation emissions, based on MSHA data.

Estimated Methane Drained: Mines that employ degasification systems emit large quantities of methane in high concentrations. Summary Table 14 lists mines according to the estimated methane drained. In contrast to ventilation emissions, no agency requires mines to report the amount of methane they drain, and actual methane drainage data are therefore unavailable. Thus, EPA has estimated the volume of methane drained based on estimated drainage efficiency, as defined below. Based on information obtained from MSHA district offices, EPA has developed a list of 25 U.S. mines that have drainage systems in place. A list of the mines that have drainage systems is shown in Summary Table 12. For the purpose of estimating emissions from drainage systems, if a mine is listed as having a drainage system in place, it is assumed that the system was in place from 1993 onward.

Specific Emissions: "Specific emissions" refers to the total amount of methane liberated per ton of coal that is mined. Specific emissions are an important indicator of whether a mine is a good candidate for a methane recovery project. In general, mines with higher specific emissions tend to have stronger potential for methane recovery. Summary Table 13 shows a list of mines ordered according to specific emissions. Note that the coal production and methane liberation values shown in this report have been rounded, whereas the data actually used to calculate the specific emissions values have not been rounded. Therefore, the specific emissions data shown in this report may differ from results that the reader would obtain by dividing the methane liberation values by the coal production values. This difference is strictly due to rounding, and does not reflect any error in the calculation of methane recovered.

Estimated Current Drainage Efficiency: In order to estimate the amount of methane emitted at mines that are believed to have drainage systems, it was assumed that these emissions would represent from 20-60 percent of total methane liberated from the mine. Thus, for mines that have drainage systems, ventilation emissions were assumed to equal 40-80 percent of total liberation, with emissions from drainage systems accounting for the remaining 20-60 percent. For mines that do not already have drainage systems in place, ventilation emissions are assumed to equal 100 percent of total methane liberation.

The assumption that methane drainage accounts for 40 percent of total methane liberation is probably conservative for some mines, but optimistic for others. Therefore, drainage estimates of 20, 40, and 60% were calculated for each mine profile. Accordingly, the drainage efficiency of 40 percent is merely an arbitrarily chosen value, and may not reflect actual conditions at any one mine.

Drainage System Used: Twenty of the mines profiled in this report use some type of drainage (or degasification) system to capture coal mine methane. Drainage systems used include vertical pre-mine (drilled in advance of mining), vertical gob wells, long-hole horizontal pre-mine, and horizontal pre-mine. Summary Table 9 lists mines by drainage system used.

Energy and Environmental Value of Emissions Reduction

This section presents information on the environmental and energy benefits that may be achieved by developing a methane recovery project at a mine.

CO_2 Equivalent of CH_4 Emissions Reductions (mmt/yr). This statistic shows the carbon dioxide (CO_2) equivalent of the *annual* methane emissions reductions that may potentially be achieved at each mine. The CO_2 equivalent of the potential methane emissions reductions is shown in order to facilitate the comparison of the environmental benefits of coal mine methane recovery projects to other greenhouse gas mitigation projects. The potential quantity of methane that may be recovered from a mine -- which represents the emissions reductions that may be achieved -- is converted to a CO_2 equivalent as follows:

CO_2 equivalent (million tons/yr) = [CH_4 liberated (mmcf/yr) x recovery efficiency (20%, 40% and 60%) x 19.2 g CH_4/cf x 21 g CO_2/ 1 g CH_4 x 1 lb / 453.59 g x 1 ton / 2000 lbs]

where: 21 is the global warming potential (GWP) of emitting 1 gram of methane compared to emitting 1 gram of carbon dioxide over a 100 year time period[9]

19.2 g/cf is the density of methane at 60 degrees F and atmospheric pressure

The CO_2 equivalent is shown assuming a 20%, 40% and 60% recovery efficiencies (i.e., the portion of total methane emissions that are recovered and utilized). Summary Table 14 shows the CO_2 equivalent of the potential methane emissions reductions that may be achieved at each mine.

CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion: This ratio shows the reduction in CO_2 emissions from the combustion of methane instead of coal produced at the mine. The ratio is calculated by converting the methane recovered into a CO_2 equivalent (as described above) and dividing by the annual CO_2 emitted from the combustion of coal produced at the mine. In order to calculate the CO_2 emissions from coal combustion, the annual coal production is multiplied by the Btu value of the coal (see general information section for Btu value). Next, this value is multiplied by an emissions factor of from 203 to 210 lbs CO_2 per million Btu.[10] Finally, the value is multiplied by 99 percent to account for the fraction oxidized. The formula is as follows:

[CO_2 equivalent of potential annual CH_4 emissions reductions (lbs)] / [annual coal production (tons) x Btus/ton x lbs CO_2 emitted / Btu x 99% (fraction oxidized)].

The ratio is calculated assuming a 20%, 40% and 60% recovery efficiencies.

[9] For further information on the global warming potential of various greenhouse gases see Intergovernmental Panel on Climate Change (1997)

[10] The emissions factor used is based on average state values reported in Energy Information Administration (1992). For the states examined in this report, values range from about 203 to 210 lbs CO_2/mm Btu.

Btu Value of Recovered Methane/Btu Value of Coal Produced: In order to calculate this ratio, the potential annual quantity of methane recovered is multiplied by a value of 1000 Btus/cf. Annual coal production is multiplied by the Btus/ton value for the mine. The ratio of the energy value of the methane recovered to the energy value of the coal produced is then calculated. The formula is as follows:

[Recovered methane (cf/yr) x 1000 Btus/cf] / [coal production (tons) x Btus/ton]

As with the other statistics in this section, the ratio is calculated assuming a 20%, 40% and 60% recovery efficiencies. In comparison with the first ratio (CO_2 equivalent of methane/ CO_2 emissions from coal combustion), the energy value of the methane emissions is a much smaller fraction of the energy value of the coal production.

Power Generation Potential

This section presents data relevant to the examination of whether the mine is a good candidate for an on-site electricity generation project.

Utility Electricity Supplier: The utility that supplies electricity to the mine is listed here, based on the service areas reported in the *North American Electric Power Atlas, 2001 Edition* (Electric Power, 2002). Summary Table 15 lists the utilities that sell power to the profiled mines.

Parent of Utility: The parent company of the local electric utility is also shown. This information is also based on the *North American Electric Power Atlas, (Electric Power, 2002).*

Total Electricity Demand (MW): The annual electricity demand -- including the electricity demands of the mine plus the additional electricity load of the preparation plant -- is calculated as follows:

Mine Electricity Demand Assumptions:

- Total annual electricity needs are estimated by assuming that 24 kwh are needed for each ton of coal mined.
- Ventilation systems are run 24 hours a day, 365 days a year (8760 hours a year) and account for about 25% of total electricity needs.
- Other mine operations run 16 hours a day for 220 days a year (3520 hours a year) and account for 75% of total electricity needs.

Demand (kwh/yr): 24 kwh/ton x tons mined/yr = kwhs/yr
Demand (kW): [(75% x kwhs/yr)/(3520 hours)] + [(25% x kwhs/yr)/8760 hours)]
(mine operations) + *(mine ventilation)*

Prep Plant Electricity Demand Assumptions:

Prep plants require 6 kwh/ton of coal processed
Prep plants are operated 16 hours a day, 220 days a year (3520 hours)
Demand (kwh/yr): 6 kwh/ton x tons/year
Demand (kW): [kwh/yr / 3520 hours]

Electricity Demand (GWh/year): The annual continuous electricity demand -- including the electricity demands of the mine plus the additional electricity load of the preparation plant -- is calculated as follows:

Mine Electricity Demand Assumptions:

> Total annual electricity needs are estimated by assuming that 24 kwh are needed for each ton of coal mined.
>
> Demand (kwh/yr): 24 kwh/ton x tons mined/yr = kwhs/yr
>
> Demand (GWh/year): [Demand (kwh/yr)]/ 10^6

Prep Plant Electricity Demand Assumptions:

> Prep plants require 6 kwh/ton of coal processed
>
> Demand (kwh/yr): 6 kwh/ton x tons/year
>
> Demand (GWh/year): [Demand (kwh/yr)]/ 10^6

Potential Electric Generating Capacity (kW): The potential electric generating capacity (i.e., the amount of electricity that could be generated from recovered coal mine methane) is estimated by assuming that there are 1000 Btus/cf of methane recovered and that the heat rate of a generator would be about 11,000 Btus/cf, which is a conservative assumption for a heat rate given that a gas turbine would likely be used for such a project. (Other technologies such as internal combustion engines may also be used to generate electricity.) The capacity is estimated based on 20%, 40% and 60% recovery efficiencies (i.e. percentage of total emissions recovered). The formula is:

Generating Capacity (kW): CH_4 liberated in cf/day x 1 day/24 hours x 1000 Btus/cf x kwh/11,000 Btus.

Summary Table 16 lists the mines according to their potential electric generating capacity in MW.

Pipeline Potential

This section presents data that are useful in determining whether a mine is a good candidate for a pipeline sales project.

Potential Annual Gas Sales: Potential annual gas sales are estimated by multiplying total daily methane emissions by 365 days per year and then multiplying that value by the assumed recovery efficiency. Potential annual gas sales are calculated for 20 %, 40%, and a 60% assumed recovery efficiencies and are presented in billion cubic feet. The estimated amount of gas that could be produced for sale to a pipeline at each candidate mine is shown in Summary Table 20.

Description of Surrounding Terrain: The terrain surrounding the mine is described, as this is an important factor in determining the costs of laying gathering lines for the project. While many mines in Appalachia are located in hilly or mountainous terrain, mines in the Illinois Basin tend to be located on relatively flat plains.

Transmission Pipeline in County: A "yes" indicates that an existing commercial pipeline runs through the county.

Owner of Nearest Pipeline: The corporate owner of the pipeline located closest to the mine is provided. If a mine is utilizing methane it is assumed that the owner of the nearest pipeline is the mine itself. The mine's pipeline would connect the mine to a commercial pipeline.

Distance to Pipeline: The estimated distance from the closest pipeline to the mine is provided. Some western coal mines may be more than 20 miles from the nearest pipeline. In contrast, most eastern coal mines are located within ten miles of a commercial pipeline. However, while a mine may be located within close proximity to an existing gas pipeline, there are no guarantees that the pipeline will have enough capacity to take the gas produced from a coal mine. In particular, the Appalachian region tends to have limited pipeline capacity. If a mine is using methane it is assumed that the distance to the nearest commercial pipeline is zero, since the mine would have to have a pipeline in place to transport the gas.

Pipeline Diameter: The diameter (in inches) of the nearest pipeline is provided.

Other Utilization Possibilities

This section addresses the possibility of using methane in a nearby coal-fired power plant.

Name of Nearby Coal Fired Power Plant: A few of the mines profiles here are located less than ten miles from a coal-fired power plant. For these mines, the name of the nearby power plant is listed. The source of this information, along with the estimated distance to the power plant and the plant capacity is taken from the *North American Electric Power Atlas, (Electric Power, 2002).*

Distance to Plant: The profile shows the estimated distance between the mine and the nearby power plant.

Comments: This section briefly describes any other important information about the mine that is not listed in any other section.

Ventilation Air Methane Emissions

Table 18 in Chapter 5 summarizes certain characterizations of ventilation air methane (VAM) emissions that were derived for each mine from Mine Safety and Health Administration (MSHA) quarterly sampling data. For each shaft at gassy mines, MSHA samples methane concentration and ventilation airflow. The shaft-specific data were aggregated to derive weighted average methane emissions for each mine.

5. Mine Summary Tables

List of Summary Tables:

Table 1: Mines Listed Alphabetically

Mine Name	State	Mine Name	State
Aberdeen	UT	Mc Elroy Mine	WV
Bailey Mine	PA	Mine #1	KY
Baker	KY	Monterey No. 1	IL
Blacksville No. 2	WV	North River Mine	AL
Blue Creek No. 4	AL	Oak Grove Mine	AL
Blue Creek No. 5	AL	Pattiki Mine	IL
Blue Creek No. 7	AL	Pinnacle	UT
Bowie No. 2	CO	Pollyanna No. 8	OK
Buchanan Mine	VA	Pontiki No. 2	KY
Cadiz Portal	OH	Powhatan No. 6 Mine	OH
Camp #11	KY	Rend Lake	IL
Cardinal No. 2	KY	Robinson Run No. 95	WV
Clean Energy No. 1	KY	San Juan South	NM
Cumberland Mine	PA	Sanborn Creek	CO
Dugout Canyon Mine	UT	Sentinel Mine	WV
Eighty-Four Mine	PA	Shoal Creek	AL
Emerald Mine	PA	Shoemaker Mine	WV
Enlow Fork Mine	PA	Tiller No. 1	VA
Federal No. 2	WV	Upper Big Branch - South	WV
Galatia	IL	US Steel No. 50	WV
Gibson	IN	VP No. 8	VA
Harris No. 1 Mine	WV	Wabash	IL
Justice #1	WV	West Elk Mine	CO
Leeco No. 68	KY	West Ridge Mine	UT
Loveridge No. 22	WV	Whitetail Kittanning Mine	WV

Table 2: Mines Listed by State and County

Mine Name	State	County	Mine Name	State	County
North River Mine	AL	Fayette	Pollyanna No. 8	OK	Le Flore
Oak Grove Mine	AL	Jefferson	Bailey Mine	PA	Greene
Shoal Creek	AL	Jefferson	Cumberland Mine	PA	Greene
Blue Creek No. 4	AL	Tuscaloosa	Emerald Mine	PA	Greene
Blue Creek No. 5	AL	Tuscaloosa	Enlow Fork Mine	PA	Greene
Blue Creek No. 7	AL	Tuscaloosa	Eighty-Four Mine	PA	Washington
Bowie No. 2	CO	Delta	Aberdeen	UT	Carbon
Sanborn Creek	CO	Gunnison	Dugout Canyon Mine	UT	Carbon
West Elk Mine	CO	Gunnison	Pinnacle	UT	Carbon
Rend Lake	IL	Jefferson	West Ridge Mine	UT	Carbon
Monterey No. 1	IL	Macoupin	Buchanan Mine	VA	Buchanan
Galatia	IL	Saline	VP No. 8	VA	Buchanan
Wabash	IL	Wabash	Tiller No. 1	VA	Tazewell
Pattiki Mine	IL	White	Sentinel Mine	WV	Barbour
Gibson	IN	Gibson	Harris No. 1 Mine	WV	Boone
Cardinal No. 2	KY	Hopkins	Justice #1	WV	Boone
Pontiki No. 2	KY	Martin	Robinson Run No. 95	WV	Harrison
Leeco No. 68	KY	Perry	Loveridge No. 22	WV	Marion
Clean Energy No. 1	KY	Pike	Mc Elroy Mine	WV	Marshall
Mine #1	KY	Pike	Shoemaker Mine	WV	Marshall
Camp #11	KY	Union	Blacksville No. 2	WV	Monongalia
Baker	KY	Webster	Federal No. 2	WV	Monongalia
San Juan South	NM	San Juan	Whitetail Kittanning Mine	WV	Preston
Powhatan No. 6 Mine	OH	Belmont	Upper Big Branch - South	WV	Raleigh
Cadiz Portal	OH	Harrison	US Steel No. 50	WV	Wyoming

Table 3: Mines Listed by Coal Basin

Coal Basin/ Mine Name	Estimated Specific Emissions (cf/ton)
Arkoma	
Pollyanna No. 8	827
Central Appalachian	
Buchanan Mine	1,463
Cardinal No. 2	133
Clean Energy No. 1	231
Harris No. 1 Mine	106
Leeco No. 68	201
Mine #1	202
Pontiki No. 2	182
Tiller No. 1	397
Upper Big Branch - South	125
US Steel No. 50	1,928
VP No. 8	11,063
Central Rockies	
Bowie No. 2	25
Dugout Canyon Mine	103
Illinois	
Baker	366
Camp #11	103
Galatia	436
Gibson	291
Monterey No. 1	83
Pattiki Mine	408
Rend Lake	290
Wabash	382
Northern Appalachian	
Bailey Mine	241
Blacksville No. 2	658
Cadiz Portal	174
Cumberland Mine	888
Eighty-Four Mine	1,022
Emerald Mine	410
Enlow Fork Mine	346
Federal No. 2	1,336
Justice #1	275
Loveridge No. 22	1,835
Mc Elroy Mine	382
Powhatan No. 6 Mine	114
Robinson Run No. 95	375
Sentinel Mine	1,208
Shoemaker Mine	372
Whitetail Kittanning Mine	142
San Juan	
San Juan South	166
Uinta	
Aberdeen	848
Pinnacle	383
Sanborn Creek	908
West Elk Mine	1,169
West Ridge Mine	120
Warrior	
Blue Creek No. 4	2,290
Blue Creek No. 5	5,865
Blue Creek No. 7	4,887
North River Mine	629
Oak Grove Mine	1,751
Shoal Creek	615

Table 4: Mines Listed by Coalbed

Mine Name	Coalbed	Mine Name	Coalbed
Cardinal No. 2	#11	Blacksville No. 2	Pittsburgh
Leeco No. 68	Aberdeen	Loveridge No. 22	Pittsburgh
West Elk Mine	B & E Seams	Mc Elroy Mine	Pittsburgh
Sanborn Creek	B and D Seams	Robinson Run No. 95	Pittsburgh
Bowie No. 2	B&D Seams	Shoemaker Mine	Pittsburgh
Blue Creek No. 7	Blue Creek	Bailey Mine	Pittsburgh
Oak Grove Mine	Blue Creek	Federal No. 2	Pittsburgh
Blue Creek No. 5	Blue Creek	Eighty-Four Mine	Pittsburgh
Shoal Creek	Blue Creek, Mary Lee	Cumberland Mine	Pittsburgh No. 8
Blue Creek No. 4	Blue Creek, Mary Lee	Powhatan No. 6 Mine	Pittsburgh No. 8
Harris No. 1 Mine	Eagle	Emerald Mine	Pittsburgh No. 8
Upper Big Branch - South	Eagle, Powellton	Buchanan Mine	Pocahantas No. 3
Dugout Canyon Mine	Gilson, Rock Canyon	VP No. 8	Pocahontas No. 3
Pollyanna No. 8	Hart	US Steel No. 50	Pocahontas No. 3
Rend Lake	Herrin No. 6	Mine #1	Pond Creek
Pattiki Mine	Herrin No. 6	Clean Energy No. 1	Pond Creek
Monterey No. 1	Herrin No. 6	Pontiki No. 2	Pond Creek
Sentinel Mine	Kittanning	Justice #1	Powellton, Buffalo Crk
Whitetail Kittanning Mine	Kittanning	North River Mine	Pratt
Pinnacle	L. Sunnyside, Gilson, Aberdeen	Galatia	Springfield
Aberdeen	L. Sunnyside, Gilson, Aberdeen	Wabash	Springfield No. 5
Cadiz Portal	Lower Freeport	Gibson	Springfield No.5
West Ridge Mine	Lower Sunnyside	Tiller No. 1	Tiller
San Juan South	No 9, No. 8	Baker	W. Kentucky No. 13
Enlow Fork Mine	Pittsburgh	Camp #11	W. Kentucky No. 9

Table 5: Mines Listed by Company

Parent Company	Owner	Mine Name
Aero Energy Co. Inc.		
	Aero Energy Co. Inc.	Mine #1
Alliance Coal LLC		
	White County Coal L.L.C.	Pattiki Mine
Alliance Resources Partners		
	Gibson County Coal LLC	Gibson
American Coal Company		
	The American Coal Co.	Galatia
American Electric Power		
	AEP Coal, Inc.	Cadiz Portal
Andalex Resources, Inc.		
	Andalex Resources, Inc.	Aberdeen
	Andalex Resources, Inc.	Pinnacle
	West Ridge Resources	West Ridge Mine
Anker Energy		
	Philippi Development, Inc.	Sentinel Mine
Arch Coal Co.		
	Canyon Fuel Co., LLC	Dugout Canyon Mine
	Mountain Coal Co.	West Elk Mine
BHP/Billiton		
	San Juan Coal Co.	San Juan South
Chevron Texaco		
	Pittsburg & Midway Coal Mining	North River Mine
CONSOL Energy		
	Consolidation Coal Co.	Rend Lake

Table 5: Mines Listed by Company (cont.)

Parent Company	Owner	Mine Name
Consol Energy Inc.		
	Consol Energy Inc.	Shoemaker Mine
	Consol Energy Inc.	Enlow Fork Mine
	Consol Energy Inc.	VP No. 8
	Consol Energy Inc.	Bailey Mine
	Consol Energy Inc.	Robinson Run No. 95
	Consol Energy Inc.	Blacksville No. 2
	Consol Energy Inc.	Buchanan Mine
	Consol Energy Inc.	Loveridge No. 22
	Consol Energy Inc.	Mc Elroy Mine
	Eighty-Four Mining Co.	Eighty-Four Mine
Drummond Co., Inc.		
	Drummond Co., Inc.	Shoal Creek
El Paso Corporation		
	Coastal Coal Co.	Whitetail Kittanning Mine
Excel Mining		
	Excel Mining LLC	Pontiki No. 2
ExxonMobil Coal & Minerals		
	Monterey Coal Co.	Monterey No. 1
HMI		
	HMI	Pollyanna No. 8
James River Coal Co.		
	Leeco, Inc.	Leeco No. 68
Lodestar Energy, Inc.		
	Lodestar Energy, Inc	Baker
Massey Energy Co.		
	Independence Coal Co.	Justice #1
	Knox Creek Coal Corp.	Tiller No. 1
	Massey Energy Co.	Clean Energy No. 1
	Performance Coal Co.	Upper Big Branch - South
Ohio Valley Coal Company		
	Ohio Valley Coal Co.	Powhatan No. 6 Mine

Table 5: Mines Listed by Company (cont.)

Parent Company	Owner	Mine Name
Oxbow Mining, Inc.		
	Oxbow Mining, Inc.	Sanborn Creek
Peabody Energy		
	Peabody Energy	Harris No. 1 Mine
	Peabody Energy	Federal No. 2
	Peabody Energy	Camp #11
RAG American Coal Co.		
	RAG Cumberland Resources, LP	Cumberland Mine
	RAG Emerald Resources, LP	Emerald Mine
RAG Coal International AG		
	RAG Midwest Coal Holding Co.	Wabash
Roberts Brothers Coal Co.		
	Roberts Brothers Coal Co., Inc.	Cardinal No. 2
Union Pacific		
	Bowie Resources LTD.	Bowie No. 2
USX Corp.		
	U.S. Steel Mining Co., L.L.C.	Oak Grove Mine
	U.S. Steel Mining Co., L.L.C.	US Steel No. 50
Walter Industries, Inc.		
	Jim Walter Resources, Inc	Blue Creek No. 5
	Jim Walter Resources, Inc.	Blue Creek No. 7
	Jim Walter Resources, Inc.	Blue Creek No. 4

Table 6: Mines Listed by Mining Method

Mine Name	Method	Mine Name	Method
Cadiz Portal	Continuous	Blue Creek No. 5	Longwall/Continuous
Cardinal No. 2	Continuous	Blue Creek No. 7	Longwall/Continuous
Clean Energy No. 1	Continuous	Buchanan Mine	Longwall/Continuous
Gibson	Continuous	Cumberland Mine	Longwall/Continuous
Justice #1	Continuous	Dugout Canyon Mine	Longwall/Continuous
Leeco No. 68	Continuous	Eighty-Four Mine	Longwall/Continuous
Mine #1	Continuous	Emerald Mine	Longwall/Continuous
Pattiki Mine	Continuous	Enlow Fork Mine	Longwall/Continuous
Pollyanna No. 8	Continuous	Federal No. 2	Longwall/Continuous
Pontiki No. 2	Continuous	Harris No. 1 Mine	Longwall/Continuous
Sentinel Mine	Continuous	Loveridge No. 22	Longwall/Continuous
Tiller No. 1	Continuous	Mc Elroy Mine	Longwall/Continuous
Wabash	Continuous	Monterey No. 1	Longwall/Continuous
Whitetail Kittanning Mine	Continuous	North River Mine	Longwall/Continuous
Bowie No. 2	Longwall	Oak Grove Mine	Longwall/Continuous
Camp #11	Longwall	Pinnacle	Longwall/Continuous
Galatia	Longwall	Powhatan No. 6 Mine	Longwall/Continuous
San Juan South	Longwall	Rend Lake	Longwall/Continuous
Sanborn Creek	Longwall	Robinson Run No. 95	Longwall/Continuous
West Ridge Mine	Longwall	Shoal Creek	Longwall/Continuous
Aberdeen	Longwall/Continuous	Shoemaker Mine	Longwall/Continuous
Bailey Mine	Longwall/Continuous	Upper Big Branch - South	Longwall/Continuous
Baker	Longwall/Continuous	US Steel No. 50	Longwall/Continuous
Blacksville No. 2	Longwall/Continuous	VP No. 8	Longwall/Continuous
Blue Creek No. 4	Longwall/Continuous	West Elk Mine	Longwall/Continuous

Table 7: Mines Listed by Primary Coal Use

Mine Name	Primary Use	Mine Name	Primary Use
Blue Creek No. 4	Metallurgical	Powhatan No. 6 Mine	Steam
Upper Big Branch - South	Metallurgical	Robinson Run No. 95	Steam
US Steel No. 50	Metallurgical	San Juan South	Steam
Aberdeen	Steam	Shoal Creek	Steam
Baker	Steam	Shoemaker Mine	Steam
Blacksville No. 2	Steam	Tiller No. 1	Steam
Bowie No. 2	Steam	Wabash	Steam
Cadiz Portal	Steam	West Elk Mine	Steam
Camp #11	Steam	West Ridge Mine	Steam
Cardinal No. 2	Steam	Whitetail Kittanning Mine	Steam
Cumberland Mine	Steam	Bailey Mine	Steam, Metallurgical
Dugout Canyon Mine	Steam	Blue Creek No. 5	Steam, Metallurgical
Enlow Fork Mine	Steam	Buchanan Mine	Steam, Metallurgical
Federal No. 2	Steam	Clean Energy No. 1	Steam, Metallurgical
Galatia	Steam	Eighty-Four Mine	Steam, Metallurgical
Gibson	Steam	Emerald Mine	Steam, Metallurgical
Leeco No. 68	Steam	Harris No. 1 Mine	Steam, Metallurgical
Loveridge No. 22	Steam	Justice #1	Steam, Metallurgical
Mc Elroy Mine	Steam	Mine #1	Steam, Metallurgical
Monterey No. 1	Steam	Oak Grove Mine	Steam, Metallurgical
North River Mine	Steam	Rend Lake	Steam, Metallurgical
Pattiki Mine	Steam	Sentinel Mine	Steam, Metallurgical
Pinnacle	Steam	VP No. 8	Steam, Metallurgical
Pollyanna No. 8	Steam	Blue Creek No. 7	Steam, Metallurgical, Industrial
Pontiki No. 2	Steam	Sanborn Creek	Steam, Metallurgical, Industrial

Table 8: Mines Listed by 2001 Coal Production

Mine Name	MM Tons	Mine Name	MM Tons
Bailey Mine	10.3	Whitetail Kittanning Mine	2.4
Enlow Fork Mine	10.3	VP No. 8	2.3
Galatia	7.0	West Ridge Mine	2.3
Emerald Mine	6.7	Dugout Canyon Mine	2.0
Cumberland Mine	6.7	Rend Lake	2.0
Mc Elroy Mine	6.6	Cardinal No. 2	1.9
Bowie No. 2	5.4	Mine #1	1.9
Blacksville No. 2	5.0	Pattiki Mine	1.9
West Elk Mine	5.0	Oak Grove Mine	1.8
Robinson Run No. 95	4.9	Blue Creek No. 7	1.8
Federal No. 2	4.9	Cadiz Portal	1.7
Powhatan No. 6 Mine	4.6	Gibson	1.7
Buchanan Mine	4.5	Eighty-Four Mine	1.6
Shoal Creek	4.1	Blue Creek No. 5	1.5
Shoemaker Mine	4.1	Wabash	1.5
Harris No. 1 Mine	3.7	Clean Energy No. 1	1.3
Camp #11	3.6	Leeco No. 68	1.2
Justice #1	3.4	Pontiki No. 2	1.2
Baker	3.4	Loveridge No. 22	1.1
North River Mine	3.2	San Juan South	0.7
Monterey No. 1	3.2	Tiller No. 1	0.6
US Steel No. 50	3.1	Aberdeen	0.5
Upper Big Branch - South	2.9	Pollyanna No. 8	0.4
Sanborn Creek	2.8	Sentinel Mine	0.4
Blue Creek No. 4	2.5	Pinnacle	0.3

Table 9: Mines Employing Methane Drainage Systems

Mine Name	Type of Drainage System	Estimated Current Drainage Efficiency
Bailey Mine	Vertical Gob	1%
Blacksville No. 2	Vertical Gob, Horizontal Pre-Mine	26%
Blue Creek No. 4	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	50%
Blue Creek No. 5	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	44%
Blue Creek No. 7	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	40%
Bowie No. 2	Vertical Gob	24%
Buchanan Mine	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	42%
Cumberland Mine	Vertical Gob, Horizontal Pre-Mine	28%
Emerald Mine	Vertical Gob, Horizontal Pre-Mine	22%
Enlow Fork Mine	Vertical Gob	1%
Federal No. 2	Vertical Gob, Horizontal Pre-Mine	40%
Loveridge No. 22	Vertical Gob, Horizontal Pre-Mine	40%
Oak Grove Mine	Vertical Pre-Mine, Vertical Gob	28%
Robinson Run No. 95	Vertical Gob, Horizontal Pre-Mine	20%
Sanborn Creek	Vertical Gob	25%
Shoal Creek	Vertical Pre-Mine, Vertical Gob	5%
Shoemaker Mine	Vertical Gob	15%
US Steel No. 50	Directional Pre-Mine, Vertical Gob, Horizontal Pre-Mine	43%
VP No. 8	Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine	90%
West Elk Mine	Vertical Gob	25%

Table 10: Mines Listed by Estimated Total Methane Liberated in 2001

Mine Name	MMCF/D	Mine Name	MMCF/D
VP No. 8	70.6	Pattiki Mine	2.1
Blue Creek No. 7	24.5	Rend Lake	1.5
Blue Creek No. 5	23.6	Wabash	1.5
Federal No. 2	17.9	Powhatan No. 6 Mine	1.4
Buchanan Mine	17.9	Sentinel Mine	1.4
US Steel No. 50	16.6	Gibson	1.3
Cumberland Mine	16.2	Aberdeen	1.2
West Elk Mine	16.1	Harris No. 1 Mine	1.1
Blue Creek No. 4	15.9	Mine #1	1.0
Enlow Fork Mine	9.8	Upper Big Branch - South	1.0
Blacksville No. 2	9.1	Camp #11	1.0
Oak Grove Mine	8.8	Pollyanna No. 8	0.9
Galatia	8.4	Whitetail Kittanning Mine	0.9
Emerald Mine	7.6	Clean Energy No. 1	0.9
Sanborn Creek	7.0	Cadiz Portal	0.8
Shoal Creek	6.9	West Ridge Mine	0.8
Mc Elroy Mine	6.9	Monterey No. 1	0.7
Bailey Mine	6.8	Cardinal No. 2	0.7
Loveridge No. 22	5.8	Leeco No. 68	0.7
North River Mine	5.6	Tiller No. 1	0.6
Robinson Run No. 95	5.0	Pontiki No. 2	0.6
Eighty-Four Mine	4.6	Dugout Canyon Mine	0.6
Shoemaker Mine	4.2	Bowie No. 2	0.4
Baker	3.4	San Juan South	0.3
Justice #1	2.5	Pinnacle	0.3

Table 11: Mines Listed by Daily Ventilation Emissions in 2001

Mine Name	MMCF/D	Mine Name	MMCF/D
Blue Creek No. 7	14.7	Pattiki Mine	2.1
Blue Creek No. 5	13.2	Rend Lake	1.5
West Elk Mine	12.1	Wabash	1.5
Cumberland Mine	11.7	Powhatan No. 6 Mine	1.4
Federal No. 2	10.7	Sentinel Mine	1.4
Buchanan Mine	10.3	Gibson	1.3
Enlow Fork Mine	9.7	Aberdeen	1.2
US Steel No. 50	9.5	Harris No. 1 Mine	1.1
Galatia	8.4	Mine #1	1.0
Blue Creek No. 4	8.0	Upper Big Branch - South	1.0
VP No. 8	7.3	Camp #11	1.0
Mc Elroy Mine	6.9	Pollyanna No. 8	0.9
Bailey Mine	6.7	Whitetail Kittanning Mine	0.9
Blacksville No. 2	6.7	Clean Energy No. 1	0.9
Shoal Creek	6.6	Cadiz Portal	0.8
Oak Grove Mine	6.3	West Ridge Mine	0.8
Emerald Mine	5.9	Monterey No. 1	0.7
North River Mine	5.6	Cardinal No. 2	0.7
Sanborn Creek	5.2	Leeco No. 68	0.7
Eighty-Four Mine	4.6	Tiller No. 1	0.6
Robinson Run No. 95	4.0	Pontiki No. 2	0.6
Shoemaker Mine	3.5	Dugout Canyon Mine	0.6
Loveridge No. 22	3.5	San Juan South	0.3
Baker	3.4	Pinnacle	0.3
Justice #1	2.5	Bowie No. 2	0.3

Table 12: Mines Listed by Estimated Daily Methane Drained in 2001

Mine Name	MMCF/D	Mine Name	MMCF/D
VP No. 8	63.3	Gibson	0.0
Blue Creek No. 5	10.4	Leeco No. 68	0.0
Blue Creek No. 7	9.8	Pinnacle	0.0
Blue Creek No. 4	8.0	San Juan South	0.0
Buchanan Mine	7.5	Sentinel Mine	0.0
Federal No. 2	7.1	Galatia	0.0
US Steel No. 50	7.1	Powhatan No. 6 Mine	0.0
Cumberland Mine	4.5	Pontiki No. 2	0.0
West Elk Mine	4.0	Clean Energy No. 1	0.0
Oak Grove Mine	2.5	Camp #11	0.0
Blacksville No. 2	2.4	Baker	0.0
Loveridge No. 22	2.3	Mine #1	0.0
Sanborn Creek	1.8	Wabash	0.0
Emerald Mine	1.7	Dugout Canyon Mine	0.0
Robinson Run No. 95	1.0	Pattiki Mine	0.0
Shoemaker Mine	0.6	Cadiz Portal	0.0
Shoal Creek	0.3	Monterey No. 1	0.0
Bowie No. 2	0.1	Whitetail Kittanning Mine	0.0
Bailey Mine	0.1	Upper Big Branch - South	0.0
Enlow Fork Mine	0.1	Harris No. 1 Mine	0.0
Cardinal No. 2	0.0	Tiller No. 1	0.0
North River Mine	0.0	Eighty-Four Mine	0.0
Aberdeen	0.0	West Ridge Mine	0.0
Mc Elroy Mine	0.0	Pollyanna No. 8	0.0
Justice #1	0.0	Rend Lake	0.0

Table 13: Mines Listed by Estimated Specific Emissions in 2001

Mine Name	CF/Ton	Mine Name	CF/Ton
VP No. 8	11,063	Wabash	382
Blue Creek No. 5	5,865	Robinson Run No. 95	375
Blue Creek No. 7	4,887	Shoemaker Mine	372
Blue Creek No. 4	2,290	Baker	366
US Steel No. 50	1,928	Enlow Fork Mine	346
Loveridge No. 22	1,835	Gibson	291
Oak Grove Mine	1,751	Rend Lake	290
Buchanan Mine	1,463	Justice #1	275
Federal No. 2	1,336	Bailey Mine	241
Sentinel Mine	1,208	Clean Energy No. 1	231
West Elk Mine	1,169	Mine #1	202
Eighty-Four Mine	1,022	Leeco No. 68	201
Sanborn Creek	908	Pontiki No. 2	182
Cumberland Mine	888	Cadiz Portal	174
Aberdeen	848	San Juan South	166
Pollyanna No. 8	827	Whitetail Kittanning Mine	142
Blacksville No. 2	658	Cardinal No. 2	133
North River Mine	629	Upper Big Branch - South	125
Shoal Creek	615	West Ridge Mine	120
Galatia	436	Powhatan No. 6 Mine	114
Emerald Mine	410	Harris No. 1 Mine	106
Pattiki Mine	408	Dugout Canyon Mine	103
Tiller No. 1	397	Camp #11	103
Pinnacle	383	Monterey No. 1	83
Mc Elroy Mine	382	Bowie No. 2	25

Table 14: Mines Listed by CO_2 Equivalent of Potential Annual CH_4 Emissions Reductions

(Assuming 20% - 60% Recovery Efficiency)

Mine Name	MM Tons CO_2/Yr	Mine Name	MM Tons CO_2/Yr
VP No. 8	2.29 - 6.87	Pattiki Mine	0.07 - 0.21
Blue Creek No. 7	0.79 - 2.38	Rend Lake	0.05 - 0.15
Blue Creek No. 5	0.76 - 2.29	Wabash	0.05 - 0.15
Federal No. 2	0.58 - 1.74	Powhatan No. 6 Mine	0.05 - 0.14
Buchanan Mine	0.58 - 1.74	Sentinel Mine	0.04 - 0.13
US Steel No. 50	0.54 - 1.61	Gibson	0.04 - 0.13
Cumberland Mine	0.53 - 1.58	Aberdeen	0.04 - 0.12
West Elk Mine	0.52 - 1.56	Harris No. 1 Mine	0.03 - 0.10
Blue Creek No. 4	0.52 - 1.55	Mine #1	0.03 - 0.10
Enlow Fork Mine	0.32 - 0.95	Upper Big Branch - South	0.03 - 0.10
Blacksville No. 2	0.29 - 0.88	Camp #11	0.03 - 0.10
Oak Grove Mine	0.29 - 0.86	Pollyanna No. 8	0.03 - 0.09
Galatia	0.27 - 0.82	Whitetail Kittanning Mine	0.03 - 0.09
Emerald Mine	0.25 - 0.74	Clean Energy No. 1	0.03 - 0.08
Sanborn Creek	0.23 - 0.68	Cadiz Portal	0.03 - 0.08
Shoal Creek	0.23 - 0.68	West Ridge Mine	0.02 - 0.07
Mc Elroy Mine	0.22 - 0.67	Monterey No. 1	0.02 - 0.07
Bailey Mine	0.22 - 0.66	Cardinal No. 2	0.02 - 0.07
Loveridge No. 22	0.19 - 0.56	Leeco No. 68	0.02 - 0.06
North River Mine	0.18 - 0.54	Tiller No. 1	0.02 - 0.06
Robinson Run No. 95	0.16 - 0.49	Pontiki No. 2	0.02 - 0.06
Eighty-Four Mine	0.15 - 0.45	Dugout Canyon Mine	0.02 - 0.05
Shoemaker Mine	0.14 - 0.41	Bowie No. 2	0.01 - 0.04
Baker	0.11 - 0.33	San Juan South	0.01 - 0.03
Justice #1	0.08 - 0.25	Pinnacle	0.01 - 0.03

Table 15: Mines Listed by Electric Utility Supplier

Utility Parent Company Mine Name	Utility Company
Allegheny Power Systems, Inc.	
Federal No. 2	Monongahela Power Co.
Robinson Run No. 95	Monongahela Power Co.
Whitetail Kittanning	Monongahela Power Co.
Loveridge No. 22	Monongahela Power Co.
Blacksville No. 2	Monongahela Power Co.
Bailey Mine	West Penn Power Co.
Cumberland Mine	West Penn Power Co.
Emerald Mine	West Penn Power Co.
Eighty-Four Mine	West Penn Power Co.
Enlow Fork Mine	West Penn Power Co.
American Electric Power Co., Inc.	
VP No. 8	Appalachian Power Co.
Buchanan Mine	Appalachian Power Co.
Justice #1	Appalachian Power Co.
Tiller No. 1	Appalachian Power Co.
Harris No. 1 Mine	Appalachian Power Co.
Upper Big Branch - South	Appalachian Power Co.
US Steel No. 50	Appalachian Power Co.
Leeco No. 68	Kentucky Power Co.
Pontiki No. 2	Kentucky Power Co.
Mc Elroy Mine	Wheeling Power Co.
Shoemaker Mine	Wheeling Power Co.
Cinergy	
Gibson	PSI
CIPSCO, Inc.	
Rend Lake	Central Illinois Public Service
Galatia	Central Illinois Public Service
DPL Inc.	
Powhatan No. 6 Mine	The Dayton Power & Light Co.
Dynergy, Inc.	
Monterey No. 1	Illinois Power Company

Table 15: Mines Listed by Electric Utility Supplier (cont.)

Utility Parent Company / Mine Name	Utility Company
FirstEnergy Corp.	
Cadiz Portal	Ohio Edison
KU Energy	
Mine #1	Kentucky Utilities Co.
Baker	Kentucky Utilities Co.
Clean Energy No. 1	Kentucky Utilities Co.
Camp #11	Kentucky Utilities Co.
Municipal Owned	
Pattiki Mine	Carmi Water & Light Dept.
Sentinel Mine	Philippi Municipal Electric
OGE Energy Corp.	
Pollyanna No. 8	OGE Energy Corp
PacifiCorp	
Dugout Canyon Mine	PacifiCorp
Pinnacle	PacifiCorp
West Ridge Mine	PacifiCorp
Aberdeen	Price City Utilities, Utah Power & Light
Public Service of New Mexico	
San Juan South	Public Service of New Mexico
The Southern Co.	
North River Mine	Alabama Power Co.
Blue Creek No. 7	Alabama Power Co.
Oak Grove Mine	Alabama Power Co.
Shoal Creek	Alabama Power Co.
Blue Creek No. 5	Alabama Power Co.
Blue Creek No. 4	Alabama Power Co.
Touchstone Energy Cooperatives	
West Elk Mine	Delta Montrose Elec. Assoc./Gunnison County Elec.
Sanborn Creek	Delta-Montrose Electric Coop
Bowie No. 2	Delta-Montrose Electric Coop
Cardinal No. 2	Kenergy Corp
Wabash	Wayne White Counties Elec. Coop./Norris Elec.

Table 16: Mines Listed by Potential Electric Generating Capacity
(Assuming 20% - 60% Recovery Efficiency)

Mine Name	Megawatts	Mine Name	Megawatts
VP No. 8	53.5 - 107.0	Pattiki Mine	1.6 - 3.2
Blue Creek No. 7	18.5 - 37.1	Rend Lake	1.2 - 2.3
Blue Creek No. 5	17.9 - 35.7	Wabash	1.2 - 2.3
Federal No. 2	13.5 - 27.1	Powhatan No. 6 Mine	1.1 - 2.2
Buchanan Mine	13.5 - 27.0	Sentinel Mine	1.0 - 2.1
US Steel No. 50	12.6 - 25.1	Gibson	1.0 - 2.0
Cumberland Mine	12.3 - 24.5	Aberdeen	0.9 - 1.9
West Elk Mine	12.2 - 24.4	Harris No. 1 Mine	0.8 - 1.6
Blue Creek No. 4	12.1 - 24.1	Mine #1	0.8 - 1.6
Enlow Fork Mine	7.4 - 14.8	Upper Big Branch - South	0.8 - 1.5
Blacksville No. 2	6.9 - 13.8	Camp #11	0.8 - 1.5
Oak Grove Mine	6.7 - 13.4	Pollyanna No. 8	0.7 - 1.4
Galatia	6.3 - 12.7	Whitetail Kittanning Mine	0.7 - 1.4
Emerald Mine	5.7 - 11.5	Clean Energy No. 1	0.6 - 1.3
Sanborn Creek	5.3 - 10.6	Cadiz Portal	0.6 - 1.2
Shoal Creek	5.3 - 10.5	West Ridge Mine	0.6 - 1.1
Mc Elroy Mine	5.2 - 10.5	Monterey No. 1	0.6 - 1.1
Bailey Mine	5.2 - 10.3	Cardinal No. 2	0.5 - 1.1
Loveridge No. 22	4.4 - 8.7	Leeco No. 68	0.5 - 1.0
North River Mine	4.2 - 8.4	Tiller No. 1	0.5 - 0.9
Robinson Run No. 95	3.8 - 7.6	Pontiki No. 2	0.4 - 0.9
Eighty-Four Mine	3.5 - 7.0	Dugout Canyon Mine	0.4 - 0.8
Shoemaker Mine	3.2 - 6.3	Bowie No. 2	0.3 - 0.6
Baker	2.6 - 5.1	San Juan South	0.2 - 0.5
Justice #1	1.9 - 3.8	Pinnacle	0.2 - 0.5

Table 17: Mines Listed by Potential Annual Gas Sales*
(Assuming 20% - 60% Recovery Efficiency)

Mine Name	BCF/Yr	Mine Name	BCF/Yr
VP No. 8	5.2 - 15.5	Pattiki Mine	0.2 - 0.5
Blue Creek No. 7	1.8 - 5.4	Rend Lake	0.1 - 0.3
Blue Creek No. 5	1.7 - 5.2	Wabash	0.1 - 0.3
Federal No. 2	1.3 - 3.9	Powhatan No. 6 Mine	0.1 - 0.3
Buchanan Mine	1.3 - 3.9	Sentinel Mine	0.1 - 0.3
US Steel No. 50	1.2 - 3.6	Gibson	0.1 - 0.3
Cumberland Mine	1.2 - 3.5	Aberdeen	0.1 - 0.3
West Elk Mine	1.2 - 3.5	Harris No. 1 Mine	0.1 - 0.2
Blue Creek No. 4	1.2 - 3.5	Mine #1	0.1 - 0.2
Enlow Fork Mine	0.7 - 2.1	Upper Big Branch - South	0.1 - 0.2
Blacksville No. 2	0.7 - 2.0	Camp #11	0.1 - 0.2
Oak Grove Mine	0.6 - 1.9	Pollyanna No. 8	0.1 - 0.2
Galatia	0.6 - 1.8	Whitetail Kittanning Mine	0.1 - 0.2
Emerald Mine	0.6 - 1.7	Clean Energy No. 1	0.1 - 0.2
Sanborn Creek	0.5 - 1.5	Cadiz Portal	0.1 - 0.2
Shoal Creek	0.5 - 1.5	West Ridge Mine	0.1 - 0.2
Mc Elroy Mine	0.5 - 1.5	Monterey No. 1	0.1 - 0.2
Bailey Mine	0.5 - 1.5	Cardinal No. 2	0.1 - 0.2
Loveridge No. 22	0.4 - 1.3	Leeco No. 68	0.0 - 0.1
North River Mine	0.4 - 1.2	Tiller No. 1	0.0 - 0.1
Robinson Run No. 95	0.4 - 1.1	Pontiki No. 2	0.0 - 0.1
Eighty-Four Mine	0.3 - 1.0	Dugout Canyon Mine	0.0 - 0.1
Shoemaker Mine	0.3 - 0.9	Bowie No. 2	0.0 - 0.1
Baker	0.2 - 0.7	San Juan South	0.0 - 0.1
Justice #1	0.2 - 0.6	Pinnacle	0.0 - 0.1

* Mine's actual gas sales may differ from the potential

Table 18: Mine Shaft Emissions

Mine Name	Shaft Name	Shaft Vent Air Flow CFM	Shaft Methane Flow CFM	Shaft Methane Conc. %	Weighted Mine Methane Conc. %
Aberdeen	Aberdeen	517,249	2,608	0.50	0.50
Bailey	Bleeder 12A	193,738	577	0.30	
Bailey	Bleeder 1E	219,398	2,230	1.02	0.61
Bailey	Bleeder 7B	150,385	634	0.42	
Baker	Baker	738,685	1,718	0.23	0.23
Blacksville	#2	3,001,534	4,930	0.16	0.16
Blue Creek No. 4	#4, North fan	2,023,813	6,915	0.34	0.34
Blue Creek No. 5	#5, 5-7 fan	1,656,540	7,766	0.47	0.47
Blue Creek No. 7	#7, South fan	1,563,218	6,165	0.39	0.34
Blue Creek No. 7	#7, South fan	1,904,878	5,678	0.30	
Bowie No. 2	No.2	423,768	85	0.02	0.02
Buchanan	#1	3,101,292	8,278	0.27	0.27
Cadiz Portal		245,339	932	0.38	0.38
Camp #11	#11	500,176	844	0.17	0.17
Cardinal No. 2	#2	162,322	410	0.25	0.25
Clean Energy No. 1	#1	473,924	1,264	0.27	0.27
Cumberland	#1	308,439	1,344	0.44	
Cumberland	#6	540,459	2,130	0.39	
Cumberland	Bleeder #1	167,909	2,614	1.56	0.64
Cumberland	Bleeder #2	104,608	1,306	1.25	
Cumberland	Bleeder #3	197,806	1,071	0.54	
Dugout Canyon		395,517	119	0.03	0.03
Eighty-Four Mine	Lang	130,365	917	0.70	
Eighty-Four Mine	Smith	157,370	1,389	0.88	0.38
Eighty-Four Mine	Zediker	538,793	853	0.16	
Emerald	Bleeder #4	206,017	1,806	0.88	0.35
Emerald	Emerald #7	684,012	1,318	0.19	
Enlow Fork	A11 bleeder	270,518	2,178	0.80	
Enlow Fork	B6 bleeder	255,353	1,735	0.68	0.79
Enlow Fork	E1 bleeder	238,607	2,126	0.89	
Federal No. 2	#2	2,018,301	6,259	0.31	0.31
Galatia	Galatia	1,788,102	5,802	0.32	0.32
Gibson	Gibson	208,240	469	0.23	0.23
Harris No. 1	#1	444,809	618	0.14	0.14

Table 18: Mine Shaft Emissions (cont.)

Mine Name	Shaft Name	Shaft Vent Air Flow CFM	Shaft Methane Flow CFM	Shaft Methane Conc. %	Weighted Mine Methane Conc. %
Justice #1	Licks bleeder	222,761	546	0.24	0.41
Justice #1	Whites Br bleeder	206,935	1,226	0.59	
Leeco No. 68		387,748	318	0.08	0.08
Loveridge No. 22	22	1,405,850	3,576	0.25	0.25
McElroy	McElroy	1,425,538	4,610	0.32	0.32
Mine #1	#1	605,988	685	0.11	0.11
Monterey No. 1	#1	764,901	673	0.09	0.09
North River	Cedar Cr	422,891	1,118	0.26	0.36
North River	Tyro Cr	509,182	2,249	0.44	
Oak Grove	#1	680,844	683	0.10	0.24
Oak Grove	#4	610,557	2,552	0.42	
Oak Grove	#5	463,871	1,030	0.22	
Pattiki	Pattiki	361,495	1,681	0.47	0.47
Pinnacle	Pinnacle	199,051	434	0.22	0.22
Pollyanna No. 8	No.8	185,939	182	0.10	0.10
Pontiki No. 2	#2	294,519	215	0.07	0.07
Powhatan No. 6	#6	871,079	784	0.09	0.09
Rend Lake		1,620,913	1,572	0.10	0.10
Robinson Run	Robinson Run	1,347,678	2,808	0.21	0.21
San Juan South	South	90,807	6	0.01	0.01
Sanborn Creek	Sanborn Creek	636,551	3,683	0.58	0.58
Sentinel	Sentinel	867,540	1,211	0.14	0.14
Shoal Creek	#2	514,181	1,538	0.30	0.27
Shoal Creek	#4	470,259	1,081	0.23	
Shoemaker		1,672,768	3,178	0.19	0.19
Tiller No. 1	#1	19,070	0	0.00	0.00
U.S. Steel No. 50	8A	353,691	2,477	0.70	0.50
U.S. Steel No. 50	Dale	396,627	2,496	0.63	
U.S. Steel No. 50	South Fork	649,707	1,967	0.30	
Upper Big Branch	Upper Big Branch	275,127	777	0.28	0.28
VP No. 8	#8	2,693,001	5,852	0.22	0.22
Wabash		1,063,658	1,106	0.10	0.10
West Elk	West Elk	1,519,703	7,231	0.48	0.48
West Ridge		190,696	19	0.01	0.01
Whitetail Kittanning		381,391	381	0.10	0.10

6. Profiled Mines (continued)

States with Candidate and Utilizing Mines:

Alabama

Colorado

Illinois

Indiana

Kentucky

New Mexico

Ohio

Oklahoma

Pennsylvania

Utah

Virginia

West Virginia

6. Profiled Mines

Data Summary

Below is a state-by-state summary of data pertaining to coal mine methane at the mines profiled in this report. Chapter 4 explains how these data were derived. Following this data summary section are individual mine profiles, in alphabetical order by state.

Alabama

Of the ten profiled U.S. mines that already recover and use methane, five are located in Alabama. Three of these mines are owned by Jim Walter Resources (JWR), one mine is owned by USX Corp., and one mine is owned by Drummond Coal. All five mines sell methane to pipelines. Based on information obtained from the State of Alabama, Division of Oil & Gas, these five mines recovered and sold an average of 31 mmcf/d in 2001. This recovery was drained from areas that are currently or will eventually be mined.

In addition to these mines, Alabama has one other large gassy mine that appears to be a good candidate for a methane recovery project. North River No. 1 has been in operation since 1974 and uses the longwall mining method. Table 6-1 shows that the implementation of a methane recovery and use project at the North River No. 1 Mine could reduce annual methane emissions by 0.4-1.2 Bcf/yr.

Table 6-1: Alabama Mines

Mine	Company	2001 Coal Production (mm tons)	2001 Ventilation, Drainage and Use Data[1]				
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)	Estimated Methane Used (mmcf/d)
Mines Using Methane (mines at which recovery and use projects have already been developed):							
Blue Creek No. 4	Jim Walter Res.	2.5	8.0	8.0	15.9	2,290	8.0
Blue Creek No. 5	Jim Walter Res.	1.5	13.2	10.4	23.6	5,865	10.4
Blue Creek No. 7	Jim Walter Res.	1.8	14.7	9.8	24.5	4,887	9.8
Oak Grove	USX Corp.	1.8	6.3	2.5	8.8	1,751	2.5
Shoal Creek	Drummond	4.1	6.6	0.3	6.9	615	0.3
Total for All Mines Using Methane		**11.7**	**48.8**	**31.0**	**79.8**	**-**	**31.0**
Operating But Not Using Methane:							
North River No. 1	Pitts. & Midway	3.2	5.6	0.0	5.6	629	0.0
TOTAL:[2]		**14.9**	**54.4**	**31.0**	**85.4**	**-**	**31.0**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (North River No. 1):	Methane (Bcf/yr)	CO_2 (mmt/yr)
2001 Estimated Total Emissions	2.0	0.8
Estimated Annual Avoided Emissions if Recovery Project is Implemented	0.4-1.2	0.2 - 0.5

[1] Chapter 4 explains how these were estimated.
[2] Values shown here do not always sum to totals due to rounding.

Colorado

Colorado has a number of underground mines with relatively low methane emissions, but there are also several deep and gassy mines with high emissions; these mines present potential opportunities for those interested in developing a methane recovery project in the West.

Colorado has three operating mines that are potential candidates for methane recovery: Bowie No. 2, Sanborn Creek/Elk Creek, and West Elk. Table 6-2 shows coal production, methane ventilation, and drainage data. Among the three operating mines, West Elk had the highest methane emissions, totaling 12.1 mmcf/d, in 2001. All three mines employ degasification systems using vertical gob vent boreholes. West Elk also incorporates horizontal gob wells. Table 6-2 shows that methane emissions from the three Colorado mines totaled an estimated 8.6 Bcf in 2001. Table 6-2 also shows that the implementation of methane recovery and use projects at the three mines now not using methane could reduce annual methane emissions by 1.7-5.1 Bcf/yr.

Table 6-2: Colorado Mines

Mine	Company	2001 Coal Production (mm tons)	2001 Ventilation and Drainage Data[1] Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
Bowie No. 2	Bowie Resources	5.4	0.3	0.1	0.4	25
Sanborn Creek/Elk Creek	Oxbow Mining	2.8	5.2	1.8	7.0	908
West Elk	Mountain Coal	5.0	12.1	4.0	16.1	1,165
TOTAL:[2]		**13.2**	**17.6**	**5.9**	**23.5**	**-**
Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (three mines):					**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2001 Estimated Total Emissions					8.6	3.4
Estimated Annual Avoided Emissions if Recovery Projects are Implemented					1.7 - 5.1	0.7-2.0

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.

Illinois

In general, Illinois mines tend to be less gassy than mines in other regions of the country. These mines tend to have lower specific emissions, but many have high total methane emissions depending on their yearly coal production. Accordingly, emissions reductions may be achieved at several of these mines. Coal production and methane ventilation and drainage data on these mines are shown in Table 6-3.

Five operating Illinois mines are considered to be potential candidates for methane recovery projects. None of the featured Illinois mines have a degasification system in place. Table 6-3 shows that methane emissions from the five Illinois mines totaled an estimated 5.7 Bcf in 2001. Table 6-3 shows that the implementation of methane recovery and use projects at the nine profiled mines that are operating but not currently using methane could reduce annual methane emissions by 1.1 - 3.1 Bcf/yr.

Table 6-3: Illinois Mines							
			2001 Ventilation and Drainage Data[1]				
Mine	**Company**	**2001 Coal Production (mm tons)**	**Ventilation Emissions (mmcf/d)**	**Estimated Methane Drained (mmcf/d)**	**Estimated Total Methane Liberated (mmcf/d)**	**Estimated Specific Emissions (cf/ton)**
Operating But Not Using Methane:						
Galatia No. 56	Kerr-McGee	7.0	8.4	0.0	8.4	436
Monterey No. 1	Monterey Coal	3.2	0.7	0.0	0.7	83
Pattiki	MAPCO	1.9	2.1	0.0	2.1	408
Rend Lake	CONSOL	2.0	1.5	0.0	1.5	290
Wabash	RAG America	1.5	1.5	0.0	1.5	382
TOTAL[2]:		**15.6**	**14.2**	**0.0**	**14.2**	**-**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (nine mines):	Methane (Bcf/yr)	CO_2 (mmt/yr)
2001 Estimated Total Emissions	5.7	2.3
Estimated Annual Avoided Emissions if Recovery Projects are Implemented	1.1 - 3.1	0.4 - 1.2

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.

Indiana

A single Indiana mine, the Gibson Mine, is profiled in this report. This room-and-pillar operation, which opened in 2000, is currently considered the gassiest underground mine in Indiana. The mine produced 1.7 million tons in 2001. Gibson Mine reported total methane emissions of approximately 0.47 billion cubic feet in 2001, and is not equipped with a degasification system. Based on these emissions, a methane use project may remain viable at the Gibson Mine.

Kentucky

Kentucky has seven operating mines that are good candidates for the development of methane recovery projects. The Baker Mine, which is located in the western Kentucky portion of the Illinois Coal Basin, is the gassiest in the state and only one of three mines with methane emissions greater than 1 mmcfd. The Camp No. 11 mine is also located in the Illinois Coal Basin. The Freedom Energy No. 1, Clean Energy No. 1, Pontiki No. 2, Cardinal No. 2 and Leeco No. 68 mines are located in eastern Kentucky, in the Central Appalachian Basin.

Table 6-4 shows that methane emissions from the seven Kentucky mines totaled an estimated 3.0 Bcf in 2001. Implementation of methane recovery and use projects at these eight mines could reduce annual methane emissions by an estimated 0.6 - 1.7 Bcf/yr.

Table 6-4: Kentucky Mines							
Mine	Company	2001 Coal Production (mm tons)	2001 Ventilation and Drainage Data[1]			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
Baker	Renco Coal Group	3.4	3.4	0.0	3.4	366
Camp No. 11	Peabody	3.6	1.0	0.0	1.0	103
Clean Energy No. 1	A.T. Massey	1.3	0.9	0.0	0.9	231
Cardinal No. 2		1.9	0.7	0.0	0.7	133
Freedom Energy No. 1	Sidney Coal Co.	1.9	1.0	0.0	1.0	202
Leeco No. 68		1.2	0.7	0.0	0.7	201
Pontiki No. 2	MAPCO	1.2	0.6	0.0	0.6	182
TOTAL:[2]		**14.5**	**8.3**	**0.0**	**8.3**	**-**
Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (eight mines):					**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2001 Estimated Total Emissions					3.0	1.2
Estimated Annual Avoided Emissions if Recovery Projects are Implemented					0.6 - 1.7	0.2 - 0.7

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.

New Mexico

The San Juan Mine, which is owned by the BHP Billiton, is the only New Mexico mine profiled in this report. This longwall mine opened in 2002. While little data is available, ventilation emissions are expected to exceed 1 mmcfd when the mine is in full production. The mine employs a degasification system which uses both vertical gob vent boreholes and in-mine, horizontal, pre-drainage boreholes. The mine is expected to produce up to 6 million tons of coal annually. Based on this limited information, a coalmine methane use project may be possible at the San Juan Mine.

Ohio

As with the Illinois mines, Ohio mines tend to be less gassy than mines in other regions of the country. Two operating Ohio mines are profiled in this report: the Nelms-Cadiz Portal, and the Powhatan No. 6. Coal production, ventilation, and drainage data on these mines are shown in Table 6-5. The Nelms-Cadiz Portal Mine purchases electricity generated from methane drained at the Nelms No. 1 Mine, which is permanently closed. Table 6-5 shows that the implementation of methane recovery and use projects at these two Ohio mines could reduce annual methane emissions by 0.2 - 0.5 Bcf/yr.

Table 6-5: Ohio Mines						
Mine	Company	2001 Coal Production (mm tons)	2001 Ventilation and Drainage Data[1]			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
Nelms-Cadiz Portal[2]	Harrison Mining	1.7	0.8	0.0	0.8	174
Powhatan No. 6	Ohio Valley Coal	4.6	1.4	0.0	1.4	114
TOTAL:[3]		**6.3**	**2.2**	**0.0**	**2.2**	**-**
Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (all five mines):					**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2001 Estimated Total Emissions					0.8	0.3
Estimated Annual Avoided Emissions if Recovery Projects are Implemented					0.2 - 0.5	0.1 - 0.2

[1] Chapter 4 explains how these data were estimated.
[2] As discussed in the text, the Nelms-Cadiz Portal Mine uses electricity generated from methane drained from the adjacent Nelms No. 1 Mine (about 0.18 mmcf/d).
[3] Values shown here do not always sum to totals due to rounding.

Oklahoma

A single Oklahoma mine, the Sunrise Coal Mine, is profiled in this report. This room-and-pillar operation, which opened in 1996, is currently considered the gassiest underground mine in Oklahoma. Beginning in 2001, the mine produced 0.4 million tons annually, doubled its production. As a result of the increased production, the mine had reported total methane emissions of approximately 0.33 billion cubic feet in 2001. Based on these emissions, and a history of gassy mines in the Arkoma Basin, a coalmine methane project may be viable at the Sunrise Coal Mine.

Pennsylvania

Five operating Pennsylvania mines are good candidates for methane recovery and use and are profiled in this report. Several of the mines profiled in the previous edition of this report have recently closed. These mines may also be candidates for methane projects. Coal production, ventilation, and drainage data on these mines are shown in Table 6-6.

In 2001, the five mines shown in Table 6-6 liberated about 45.0 mmcf/d (16.4 Bcf/yr) of methane. Several of these mines are located in Greene County, Pennsylvania. In fact, Greene County is the location of the two largest underground mines in the United States, CONSOL's Bailey and Enlow Fork mines. These mines are adjacent to one another and are often referred to as the Bailey-Enlow Fork complex.

Two other large and gassy mines are also located in Greene County, RAG America's Emerald No. 1 and Cumberland mines. As with Bailey and Enlow Fork, Emerald and Cumberland are located in close proximity to each other. Both mines already have drainage systems in place, although the methane is not being used at present.

Table 6-6 shows that the implementation of recovery and use projects at the five profiled Pennsylvania mines that are currently operating could reduce annual methane emissions by 3.3-9.8 Bcf/yr.

Table 6-6: Pennsylvania Mines						
Mine	Company	2001 Coal Production (mm tons)	2001 Ventilation and Drainage Data[1]			
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
Bailey	CONSOL	10.3	6.7	0.1	6.8	241
Cumberland	RAG America	6.7	11.7	4.5	16.2	888
Emerald No. 1	RAG America	6.7	5.9	1.7	7.6	410
Enlow Fork	CONSOL	10.3	9.7	0.1	9.8	346
Mine 84	CONSOL	1.6	4.6	0.0	4.6	1,022
TOTAL:[2]		**35.6**	**38.6**	**6.4**	**45.0**	**-**
Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (ten mines):					**Methane (Bcf/yr)**	**CO_2 (mmt/yr)**
2001 Estimated Total Emissions					16.4	6.6
Estimated Annual Avoided Emissions if Recovery Projects are Implemented					3.3 - 9.8	1.3 - 9.9

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.

Utah

Utah has a number of underground mines with relatively low methane emissions along the Wasatch Plateau, but it also has several deep and gassy mines with high methane emissions located nearby in the Uinta Basin. As with Colorado, these mines present potential opportunities for those interested in developing a methane recovery project in the West. Four operating Utah mines are good candidates for methane recovery and use and are profiled in this report.

The Aberdeen Mine is currently the gassiest in the state with 2001 emissions of 1.2 mmcfd. The mine is located adjacent to the Pinnacle Mine. Both of these mines, as well as the West Ridge Mine, are owned by Andalex Resources. These mines tend to have high specific emissions, and have produced high total methane emissions depending on their yearly coal production. For example, the Aberdeen Mine produced over 4 mmcfd during 1998-99, while the Pinnacle produced over 1 mmcfd during the same two years. Table 6-7 shows that the implementation of methane recovery and use projects at these four operating Utah mines could reduce annual methane emissions by 0.2 – 0.7 Bcf/yr.

Table 6-7: Utah Mines						
			2001 Ventilation and Drainage Data[1]			
Mine	Company	2001 Coal Production (mm tons)	Ventilation Emissions (mmcf/d)	Estimated Methane Drained (est.) (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Operating But Not Using Methane:						
Aberdeen	Andalex Resources	0.5	1.2	0.0	1.2	848
Dugout	Arch Coal Company	2.0	0.6	0.0	0.6	103
Pinnacle	Andalex Resources	0.3	0.3	0.0	0.3	383
West Ridge	Andalex Resources	2.3	0.8	0.0	0.8	120
TOTAL:[2]		**5.1**	**2.9**	**0.0**	**2.9**	**-**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (two mines):	Methane (Bcf/yr)	CO_2 (mmt/yr)
2001 Estimated Total Emissions	1.1	0.4
Estimated Annual Avoided Emissions if Recovery Projects are Implemented	0.2 - 0.7	0.1 - 0.3

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.

Virginia

As Table 6-8 demonstrates, two of the mines at which successful methane recovery and use projects have already been developed are located in Virginia. The Buchanan No. 1 and the VP No. 8 mines are all longwall operations, and are all owned by subsidiaries of CONSOL. The total methane drained at the two CONSOL Virginia mine properties equaled 71 mmcf/d in 2001. This number significantly exceeds ventilation emissions of 18 mmcf/d, which indicates that recovery efficiencies (up to 90% at VP No.8) are higher than standard EPA assumptions. Table 6-8 shows that Consol operates the largest active methane recovery project in the United States.

Table 6-8: Virginia Mines						
			2001 Ventilation, Drainage and Use Data[1]			
Mine	Company	2001 Coal Production (mm tons)	Ventilation Emissions (mmcf/d)	Estimated Methane Drained & Used (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)
Using Mines (mines at which recovery and use projects have already been developed):						
Buchanan No. 1	CONSOL	4.5	10.3	63.3	73.6	1,463
VP No. 8	CONSOL	2.3	7.3	7.5	14.8	11,063
Total:		**6.8**	**17.6**	**70.8**	**88.4**	**-**
Operating But Not Using Methane:						
Tiller No. 2		0.6	0.6	0.0	1.0	383
TOTAL:[2]		**7.4**	**18.2**	**70.8**	**88.4**	**-**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Mines Not Currently Using Methane (Tiller No. 2):	Methane (Bcf/yr)	CO_2 (mmt/yr)
2001 Estimated Total Emissions	0.2	0.1
Estimated Annual Avoided Emissions if Recovery Projects are Implemented	0.05 - 0.1	0.02 - 0.06

[1] Chapter 4 explains how these data were estimated.
[2] Values shown here do not always sum to totals due to rounding.

West Virginia

Of the 50 mines profiled in this report, 12 are located in West Virginia. Of these mines, three are currently recovering methane for sale. Coal production, methane ventilation, and drainage data on these mines are shown in Table 6-9.

The three profiled mines that are recovering methane for sale are the Blacksville No. 2, Federal No. 2, and Pinnacle No. 50 mines. (The methane recovery project involving the Blacksville No. 2, Humphrey No. 7, and Loveridge No. 22 mines is often considered a Pennsylvania project, for reasons explained in Chapter 3). In 2001, these mines liberated an estimated 43.6 mmcf/d (15.9 Bcf/yr), while recovering 8.6 mmcfd (3.2 Bcf/yr). Federal No. 2 recovered and sold about 0.4 Bcf of methane in 2001, while Pinnacle sold about 2.1 Bcf of methane to a gas marketing company, and the project at Blacksville No. 2 sold about 0.8 Bcf in 2001.

Seven of the West Virginia mines profiled in this report are located in the Northern Appalachian Basin; five of these are owned by subsidiaries of CONSOL. The remaining five operating mines that are profiled are located in the Central Appalachian Basin. Table 6-9 shows that the implementation of methane recovery and use projects at the nine operating mines that do not already use methane could reduce annual methane emissions by 2.1 - 6.3 Bcf/yr.

Table 6-9: West Virginia Mines								
Mine	Company	2001 Coal Production (mm tons)	2001 Ventilation, Drainage and Use Data[1]					
			Ventilation Emissions (mmcf/d)	Estimated Methane Drained (mmcf/d)	Estimated Total Methane Liberated (mmcf/d)	Estimated Specific Emissions (cf/ton)	Estimated Methane Used (mmcf/d)
Mines Using Methane (mines at which recovery and use projects have already been developed):							
Blacksville No. 2	CONSOL	5.0	6.7	2.4	9.1	658	1.0
Federal No. 2	Peabody	4.9	10.7	7.1	17.9	1,336	2.1
Pinnacle No. 50	USX Corp.	3.1	9.5	7.1	16.6	1,928	5.5
Total for All Mines Using Methane		**13.0**	**26.9**	**16.6**	**43.6**	**-**	**8.6**
Operating But Not Using Methane:							
Harris No. 1	Peabody	3.7	1.1	0.0	1.1	106	0.0
Justice No. 1	Massey	3.4	2.5	0.0	2.5	275	0.0
Loveridge No. 22	CONSOL	1.1	3.5	2.3	5.8	1,835	0.0
McElroy	CONSOL	6.6	6.9	0.0	6.9	382	0.0
Robinson Run No. 95	CONSOL	4.9	4.0	1.0	5.0	375	0.0
Sentinel	Anker	0.4	1.4	0.0	1.4	1,208	0.0
Shoemaker	CONSOL	4.1	3.5	0.6	4.1	372	0.0
Upper Big Branch So.	Massey	2.9	1.0	0.0	1.0	125	0.0
Whitetail-Kittanning	Coastal	2.4	0.9	0.0	0.9	142	0.0
TOTAL:[2]		**42.5**	**51.7**	**20.5**	**72.2**	**-**	**8.6**

Estimated Emissions and Avoided Emissions of Methane and CO_2 Equivalent From Operating Mines Not Currently Using Methane (Nine Mines):	Methane (Bcf/yr)	CO_2 (mmt/yr)
2001 Estimated Total Emissions	24.8	9.9
Estimated Annual Avoided Emissions if Recovery Project is Implemented	5.0-14.9	2.0 - 6.0

[1] Chapter 4 explains how these were estimated.
[2] Values shown here do not always sum to totals due to rounding.

6. Profiled Mines (continued)

Alabama Mines

Blue Creek No. 4
Blue Creek No. 5
Blue Creek No. 7
North River
Oak Grove
Shoal Creek

Updated: 04/01/2003 **Status:** Active

Blue Creek No. 4

GEOGRAPHIC DATA

Basin: Warrior **State:** AL

Coalbed: Blue Creek, Mary Lee **County:** Tuscaloosa

CORPORATE INFORMATION

Current Owner: Jim Walter Resources, Inc.

Parent Company: Walter Industries, Inc. **Parent Company Web Site:** www.jimwalterresources.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** No. 4 Mine

MINE ADDRESS

Contact Name: Keith Shelvey **Phone Number:** (205) 554-6450

Mailing Address: 14730 Lock 17 Rd.

City: Brookwood **State:** AL **ZIP** 35444

GENERAL INFORMATION

Number of Employees at Mine: 394 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1975 **Primary Coal Use:** Metallurgical

Life Expectancy: **Sulfur Content of Coal Produced:** 0.75% - 0.95%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 14,200

Depth to Seam (ft): 2,000 **Seam Thickness (ft):** 6.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	2.3	1.9	2.0	2.4	2.4
Estimated Total Methane Liberated (million cf/day):	22.0	23.8	19.6	21.4	15.9
Emission from Ventilation Systems:	13.4	14.1	12.0	11.0	8.0
Estimated Methane Drained:	8.6	9.8	7.6	10.3	8.0
Estimated Specific Emissions (cf/ton):	2156	2702	2151	1700	1145
Methane Recovered (million cf/day):	8.5	10.0	7.8	10.3	7.9

Estimated Current Drainage Efficiency: 50%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Blue Creek No. 4 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.5	1.0	1.5
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	7.0%	14.0%	20.9%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.6%	3.2	4.8

Power Generation Potential

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	MW	GWh/year
Total Electricity Demand (2001 data):	20.1	76.1
Mine Electricity Demand:	15.8	60.9
Prep Plant Electricity Demand:	4.3	15.2
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	12.1	105.7
Assuming 40% Recovery Efficiency:	24.1	211.3
Assuming 60% Recovery Efficiency:	36.2	317.0

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	1.2
Assuming 40% Recovery (Bcf):	2.3
Assuming 60% Recovery (Bcf):	3.5

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Mine owns pipeline that connects to trans. line

Distance to Pipeline (miles): 0.0 **Pipeline Diameter** NA

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): 8.3 **Pipeline Diameter** 24.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Ongoing CBM/CMM Project since 1980's

Updated: 04/01/2003 **Status:** Active

Blue Creek No. 5

GEOGRAPHIC DATA

Basin: Warrior **State:** AL

Coalbed: Blue Creek **County:** Tuscaloosa

CORPORATE INFORMATION

Current Owner: Jim Walter Resources, Inc

Parent Company: Walter Industries, Inc. **Parent Company Web Site:** www.jimwalterresources.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of** No. 5 Mine

MINE ADDRESS

Contact Name: Trent Thrasher, Mine Mgr. **Phone Number:** (205) 554-6550

Mailing Address: 12972 Lock 17 Rd.

City: Brookwood **State:** AL **ZIP** 35444

GENERAL INFORMATION

Number of Employees at Mine: 389 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1978 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: 2006 **Sulfur Content of Coal Produced:** 0.72% - 0.8%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 13,300

Depth to Seam (ft): 2,140 **Seam Thickness (ft):** 8.3

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	1.2	1.6	1.7	2.0	2.0
Estimated Total Methane Liberated (million cf/day):	15.0	18.6	22.7	23.9	23.6
Emission from Ventilation Systems:	9.6	11.7	14.3	14.0	13.2
Estimated Methane Drained:	5.4	6.9	8.4	10.0	10.4
Estimated Specific Emissions (cf/ton):	2947	2620	3007	2575	3284
Methane Recovered (million cf/day):	5.3	6.9	8.3	9.9	9.4

Estimated Current Drainage Efficiency: 44%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Blue Creek No. 5 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.8	1.5	2.3
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	19.1%	38.1%	57.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	4.4%	8.8	13.2%

Power Generation Potential

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	MW	GWh/year
Total Electricity Demand (2001 data):	11.6	44.0
Mine Electricity Demand:	9.1	35.2
Prep Plant Electricity Demand:	2.5	8.8
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	17.9	156.4
Assuming 40% Recovery Efficiency:	35.7	312.8
Assuming 60% Recovery Efficiency:	53.6	469.3

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	1.7
Assuming 40% Recovery (Bcf):	3.4
Assuming 60% Recovery (Bcf):	5.2

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Mine owns pipeline that connects to trans. line

Distance to Pipeline (miles): 0.0 **Pipeline Diameter** NA

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): 10.0 **Pipeline Diameter** 24.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Ongoing CBM/CMM Project Since 1980's

Updated: 04/01/2003 **Status:** Active

Blue Creek No. 7

GEOGRAPHIC DATA

Basin: Warrior **State:** AL

Coalbed: Blue Creek **County:** Tuscaloosa

CORPORATE INFORMATION

Current Owner: Jim Walter Resources, Inc.

Parent Company: Walter Industries, Inc. **Parent Company Web Site:** www.jimwalterresources.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** No. 7 Mine

MINE ADDRESS

Contact Name: Leon Robertson, Mine Mgr. **Phone Number:** (205) 554-6750

Mailing Address: 18069 Hannah Creek

City: Brookwood **State:** AL **ZIP** 35444

GENERAL INFORMATION

Number of Employees at Mine: 407 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1975 **Primary Coal Use:** Steam, Metallurgical,

Life Expectancy: 2020 **Sulfur Content of Coal Produced:** 0.58% -0.75%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,205

Depth to Seam (ft): 1790 **Seam Thickness (ft):** 5.1

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	2.6	2.5	2.1	2.4	2.4
Estimated Total Methane Liberated (million cf/day):	28.4	27.6	25.2	26.1	24.5
Emission from Ventilation Systems:	18.2	17.9	16.9	16.9	14.7
Estimated Methane Drained:	10.2	9.7	8.3	9.2	9.8
Estimated Specific Emissions (cf/ton):	2535	2667	2993	2522	2935
Methane Recovered (million cf/day):	10.4	9.7	8.4	9.3	9.9

Estimated Current Drainage Efficiency: 40%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Blue Creek No. 7 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.8	1.6	2.4
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	17.3%	34.6%	52.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	4.0%	8.0	12.0%

Power Generation Potential

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	MW	GWh/year
Total Electricity Demand (2001 data):	14.5	54.9
Mine Electricity Demand:	11.4	43.9
Prep Plant Electricity Demand:	3.1	11.0
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	18.5	162.5
Assuming 40% Recovery Efficiency:	37.1	324.9
Assuming 60% Recovery Efficiency:	55.6	487.4

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	1.8
Assuming 40% Recovery (Bcf):	3.6
Assuming 60% Recovery (Bcf):	5.4

Description of Surrounding Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Mine owns pipeline that connects to trans. line

Distance to Pipeline (miles): 0.0 **Pipeline Diameter** NA

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): 13.3 **Pipeline Diameter** 24.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Ongoing CBM/CMM Project Since 1980's

Updated: 04/01/2003 **Status:** Active

North River Mine

GEOGRAPHIC DATA

Basin: Warrior **State:** AL

Coalbed: Pratt **County:** Fayette

CORPORATE INFORMATION

Current Owner: Pittsburg & Midway Coal Mining

Parent Company: Chevron Texaco **Parent Company Web Site:** www.chevron.com/chevron_root/

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** North River No. 1

MINE ADDRESS

Contact Name: Mark Premo, Gen. Mine Mgr. **Phone Number:** (205) 333-5000

Mailing Address: 12398 New Lexington

City: Berry **State:** AL **ZIP** 35546

GENERAL INFORMATION

Number of Employees at Mine: 362 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1974 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 1.5% - 1.85%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,000

Depth to Seam (ft): 516 **Seam Thickness (ft):** 4.7

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	2.0	2.4	2.3	2.6	2.6
Estimated Total Methane Liberated (million cf/day):	2.3	2.7	5.2	3.8	5.6
Emission from Ventilation Systems:	2.3	2.7	5.2	3.8	5.6
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	426	401	819	528	629
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

North River Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.2	0.4	0.5
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	2.3%	4.5%	6.8%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.5%	1.0	1.6

Power Generation Potential

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	MW	GWh/year
Total Electricity Demand (2001 data):	25.6	96.9
Mine Electricity Demand:	20.1	77.5
Prep Plant Electricity Demand:	5.5	19.4
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	4.2	37.0
Assuming 40% Recovery Efficiency:	8.4	73.9
Assuming 60% Recovery Efficiency:	12.7	110.9

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.4
Assuming 40% Recovery (Bcf):	0.8
Assuming 60% Recovery (Bcf):	1.2

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? No

Owner of Nearest City of Berry

Distance to Pipeline (miles): 0.4 **Pipeline Diameter** 2.0

Owner of Next Nearest Pipeline: SNG Intrastate Pipeline

Distance to Next Nearest Pipeline (miles): 14.2 **Pipeline Diameter** 24.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Oak Grove Mine

GEOGRAPHIC DATA

Basin: Warrior **State:** AL

Coalbed: Blue Creek **County:** Jefferson

CORPORATE INFORMATION

Current Owner: U.S. Steel Mining Co., L.L.C.

Parent Company: USX Corp. **Parent Company Web Site:** www.uss.com/ussteel/Index.html

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: John Hedrick **Phone Number:** (205) 497-3602

Mailing Address: 8800 Oak Grove Mine

City: Adger **State:** AL **ZIP** 35006

GENERAL INFORMATION

Number of Employees at Mine: 450 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1974 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: 2023 **Sulfur Content of Coal Produced:** 0.5% - 0.55%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 14,000

Depth to Seam (ft): 1,100 **Seam Thickness (ft):** 5.8

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	2.4	2.8	2.1	2.1	2.1
Estimated Total Methane Liberated (million cf/day):	8.3	17.3	12.6	10.4	8.8
Emission from Ventilation Systems:	5.6	9.1	9.6	6.7	6.3
Estimated Methane Drained:	2.7	8.2	3.0	3.7	2.5
Estimated Specific Emissions (cf/ton):	830	1182	1633	1162	1261
Methane Recovered (million cf/day):	2.7	8.0	2.9	3.0	2.5

Estimated Current Drainage Efficiency: 28%

Drainage System Used: Vertical Pre-Mine, Vertical Gob

Oak Grove Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.3	0.6	0.9
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	5.4%	10.8%	16.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.3%	2.5	3.8

Power Generation Potential

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	MW	GWh/year
Total Electricity Demand (2001 data):	14.6	55.2
Mine Electricity Demand:	11.4	44.1
Prep Plant Electricity Demand:	3.1	11.0
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	6.7	58.5
Assuming 40% Recovery Efficiency:	13.4	117.1
Assuming 60% Recovery Efficiency:	20.0	175.6

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.6
Assuming 40% Recovery (Bcf):	1.3
Assuming 60% Recovery (Bcf):	1.9

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Mine owns pipeline that connects to trans. line

Distance to Pipeline (miles): 0.0 **Pipeline Diameter** NA

Owner of Next Nearest Pipeline: SNG Intrastate Pipeline

Distance to Next Nearest Pipeline (miles): 3.8 **Pipeline Diameter** 12.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Ongoing CBM/CMM Project Operating

Updated: 04/01/2003 **Status:** Active

Shoal Creek

GEOGRAPHIC DATA

Basin: Warrior **State:** AL

Coalbed: Blue Creek, Mary Lee **County:** Jefferson

CORPORATE INFORMATION

Current Owner: Drummond Co., Inc.

Parent Company: Drummond Co., Inc. **Parent Company Web Site:** www.drummondco.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Jay Vilseck **Phone Number:** (205) 491-6200

Mailing Address: P.O. Box 1549

City: Jasper **State:** AL **ZIP** 35501

GENERAL INFORMATION

Number of Employees at Mine: 830 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1994 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 0.63% - 1.1%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,464

Depth to Seam (ft): 1,180 **Seam Thickness (ft):** 7.5, 2.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	3.9	4.2	4.1	4.2	4.2
Estimated Total Methane Liberated (million cf/day):	3.1	7.0	6.8	6.0	6.9
Emission from Ventilation Systems:	3.1	6.0	6.6	5.7	6.6
Estimated Methane Drained:	0.0	1.0	0.2	0.3	0.3
Estimated Specific Emissions (cf/ton):	293	524	589	497	584
Methane Recovered (million cf/day):	0.0	1.0	0.2	0.3	0.4

Estimated Current Drainage Efficiency: 5%

Drainage System Used: Vertical Pre-Mine, Vertical Gob

Shoal Creek (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.2	0.5	0.7
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	2.1%	4.3%	6.4%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.5%	1.0	1.5

Power Generation Potential

Utility Electric Supplier: Alabama Power Co.

Parent Corporation of Utility: The Southern Co.

	MW	GWh/year
Total Electricity Demand (2001 data):	32.6	123.5
Mine Electricity Demand:	25.6	98.8
Prep Plant Electricity Demand:	7.0	24.7
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	5.3	46.1
Assuming 40% Recovery Efficiency:	10.5	92.1
Assuming 60% Recovery Efficiency:	15.8	138.2

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.5
Assuming 40% Recovery (Bcf):	1.0
Assuming 60% Recovery (Bcf):	1.5

Description of Surrounding Terrain: Open Hills/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: SNG Intrastate Pipeline

Distance to Pipeline (miles): NA **Pipeline Diameter** NA

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Ongoing CBM/CMM Gas Recovery Project for Pipeline Sales

6. Profiled Mines (continued)

Colorado Mines

Bowie No. 2
Sanborn Creek
West Elk

Updated: 04/01/2003 **Status:** Active

Bowie No. 2

GEOGRAPHIC DATA

Basin: Central Rockies **State:** CO

Coalbed: B&D Seams **County:** Delta

CORPORATE INFORMATION

Current Owner: Bowie Resources LTD.

Parent Company: Union Pacific **Parent Company Web Site:** http://www.uprr.com/customers/ener

Previous Owner(s): Coors Energy **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Allen Meckley **Phone Number:** (970) 929-5240

Mailing Address: 1855 Old Hwy. 133

City: Paonia **State:** CO **ZIP** 81428

GENERAL INFORMATION

Number of Employees at Mine: 140 **Mining Method:** Longwall

Year of Initial Production: 1998 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 0.5%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,000

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	0.0	1.2	1.7	5.0	5.0
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.2	0.2	0.4
Emission from Ventilation Systems:	0.0	0.0	0.2	0.2	0.3
Estimated Methane Drained:	0.0	0.0	0.0	0.1	0.1
Estimated Specific Emissions (cf/ton):	0	0	32	11	19
Methane Recovered (million cf/day):	0.0	0.0	0.0	0.0	0.0

Estimated Current Drainage Efficiency: 24%

Drainage System Used: Vertical Gob

Bowie No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.0	0.0
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.1%	0.2%	0.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.0%	0.0	0.1

Power Generation Potential

Utility Electric Supplier: Delta-Montrose Electric Coop

Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Total Electricity Demand (2001 data):	42.7	161.7
Mine Electricity Demand:	33.5	129.3
Prep Plant Electricity Demand:	9.2	32.3
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.3	2.5
Assuming 40% Recovery Efficiency:	0.6	4.9
Assuming 60% Recovery Efficiency:	0.8	7.4

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.0
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.1

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Rocky Mountain Natural Gas

Distance to Pipeline (miles): < **Pipeline Diameter** 8.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Sanborn Creek

GEOGRAPHIC DATA

Basin: Uinta **State:** CO

Coalbed: B and D Seams **County:** Gunnison

CORPORATE INFORMATION

Current Owner: Oxbow Mining, Inc.

Parent Company: Oxbow Mining, Inc. **Parent Company Web Site:**

Previous Owner(s): Pacific Basin Resources **Previous or Alternate Name of Mine:** Sanborn Creek & Elk Creek

MINE ADDRESS

Contact Name: W.R. Litwiller **Phone Number:** (970) 929-5122

Mailing Address: P.O. Box 535

City: Somerset **State:** CO **ZIP** 81434

GENERAL INFORMATION

Number of Employees at Mine: 178 **Mining Method:** Longwall

Year of Initial Production: 1991 **Primary Coal Use:** Steam, Metallurgical,

Life Expectance 2016 **Sulfur Content of Coal Produced:** 0.5% - 0.62%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,370

Depth to Seam (ft): 1,000 **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	1.6	1.5	1.1	2.2	2.2
Estimated Total Methane Liberated (million cf/day):	7.1	7.3	5.3	7.0	7.0
Emission from Ventilation Systems:	7.1	7.3	5.3	5.3	5.2
Estimated Methane Drained:	0.0	0.0	0.0	1.8	1.8
Estimated Specific Emissions (cf/ton):	1609	1744	1790	890	680
Methane Recovered (million cf/day):	0.0	0.0	0.0	0.0	0.0

Estimated Current Drainage Efficiency: 25%

Drainage System Used: Vertical Gob

Sanborn Creek (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.2	0.5	0.7
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	3.2%	6.3%	9.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.7%	1.5	2.2

Power Generation Potential

Utility Electric Supplier: Delta-Montrose Electric

Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Total Electricity Demand (2001 data):	22.3	84.3
Mine Electricity Demand:	17.5	67.5
Prep Plant Electricity Demand:	4.8	16.9
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	5.3	46.4
Assuming 40% Recovery Efficiency:	10.6	92.8
Assuming 60% Recovery Efficiency:	15.9	139.2

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.5
Assuming 40% Recovery (Bcf):	1.0
Assuming 60% Recovery (Bcf):	1.5

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Rocky Mountain Natural Gas

Distance to Pipeline (miles): < 25 miles **Pipeline Diameter** 8.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments: Closed In 2003, Adjacent Elk Creek Mine Opened in 2003

Updated: 04/01/2003 **Status:** Active

West Elk Mine

GEOGRAPHIC DATA

Basin: Uinta **State:** CO

Coalbed: B & E Seams **County:** Gunnison

CORPORATE INFORMATION

Current Owner: Mountain Coal Co.

Parent Company: Arch Coal Co. **Parent Company Web Site:** www.archcoal.com

Previous Owner(s): Atlantic Richfield/ITOCHU **Previous or Alternate Name of Mine:** Mt. Gunnison

MINE ADDRESS

Contact Name: Gene DiClaudio, Mine Manager **Phone Number:** (970) 929-5015

Mailing Address: P.O. Box 591

City: Somerset **State:** CO **ZIP** 81434

GENERAL INFORMATION

Number of Employees at Mine: 341 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1982 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 0.36% - 0.78%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 11,700

Depth to Seam (ft): 1,000 - 2,000 **Seam Thickness (ft):** 12

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	5.6	5.9	7.1	3.4	3.4
Estimated Total Methane Liberated (million cf/day):	9.0	9.3	11.8	15.7	16.1
Emission from Ventilation Systems:	9.0	9.3	11.8	11.8	12.1
Estimated Methane Drained:	0.0	0.0	0.0	3.9	4.0
Estimated Specific Emissions (cf/ton):	590	575	607	1283	876
Methane Recovered (million cf/day):	0.0	0.0	0.0	0.0	0.0

Estimated Current Drainage Efficiency: 25%

Drainage System Used: Vertical Gob

West Elk Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.5	1.0	1.6
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	4.3%	8.6%	12.9%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.0%	2.0	3.0

Power Generation Potential

Utility Electric Supplier: Delta Montrose Elec. Assoc./Gunnison County Elec. Assoc.
Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Total Electricity Demand (2001 data):	39.8	150.7
Mine Electricity Demand:	31.3	120.5
Prep Plant Electricity Demand:	8.6	30.1
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	12.2	106.7
Assuming 40% Recovery Efficiency:	24.4	213.4
Assuming 60% Recovery Efficiency:	36.5	320.1

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	1.2
Assuming 40% Recovery (Bcf):	2.3
Assuming 60% Recovery (Bcf):	3.5

Description of Surrounding Terrain: Hilly/Mountainous

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Rocky Mountain Natural Gas

Distance to Pipeline (miles): < 25 miles **Pipeline Diameter** 8.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments:

6. Profiled Mines (continued)

Illinois Mines

Galatia
Monterey No. 1
Pattiki
Rend Lake
Wabash

Updated: 04/01/2003 **Status:** Active

Galatia

GEOGRAPHIC DATA

Basin: Illinois **State:** IL

Coalbed: Springfield **County:** Saline

CORPORATE INFORMATION

Current Owner: The American Coal Co.

Parent Company: American Coal Company **Parent Company Web Site:**

Previous Owner(s): Kerr-McGee Coal Corp. **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Eric S. Grimm **Phone Number:** (618) 268-6311

Mailing Address: P.O. Box 727

City: Harrisburg **State:** IL **ZIP** 62946

GENERAL INFORMATION

Number of Employees at Mine: 585 **Mining Method:** Longwall

Year of Initial Production: 1983 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 1.2%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,000

Depth to Seam (ft): 400 **Seam Thickness (ft):** 7.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	5.0	5.5	6.5	7.3	7.3
Estimated Total Methane Liberated (million cf/day):	9.3	8.6	8.6	10.3	8.4
Emission from Ventilation Systems:	9.3	8.6	8.6	10.3	8.4
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	681	574	483	509	436
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Galatia (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.3	0.5	0.8
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.6%	3.2%	4.8%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.7	1.1

Power Generation Potential

Utility Electric Supplier: Central Illinois Public Service

Parent Corporation of Utility: CIPSCO, Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	55.6	210.3
Mine Electricity Demand:	43.6	168.2
Prep Plant Electricity Demand:	11.9	42.1
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	6.3	55.6
Assuming 40% Recovery Efficiency:	12.7	111.2
Assuming 60% Recovery Efficiency:	19.0	166.8

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.6
Assuming 40% Recovery (Bcf):	1.2
Assuming 60% Recovery (Bcf):	1.8

Description of Surrounding Terrain: Open Hills/Irregular Plains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Texas Eastern Transmission Co.

Distance to Pipeline (miles): 0.8 **Pipeline Diameter** 24.0

Owner of Next Nearest Pipeline: Trunkline

Distance to Next Nearest Pipeline (miles): 8.0 miles **Pipeline Diameter** 26"

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Gassiest Mine in the Illinois Basin

Updated: 04/01/2003 **Status:** Active

Monterey No. 1

GEOGRAPHIC DATA

Basin: Illinois **State:** IL

Coalbed: Herrin No. 6 **County:** Macoupin

CORPORATE INFORMATION

Current Owner: Monterey Coal Co.

Parent Company: ExxonMobil Coal & Minerals Co. **Parent Company Web Site:** www.exxonmobil.com/Corporate

Previous Owner(s): **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Howard C. Schulz, GM **Phone Number:** (217) 854-3291

Mailing Address: 14300 Brushy Mound

City: Carlinville **State:** IL **ZIP** 62626

GENERAL INFORMATION

Number of Employees at Mine: 326 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1970 **Primary Coal Use:** Steam

Life Expectancy: 2010 **Sulfur Content of Coal Produced:** 0.9%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 10,300

Depth to Seam (ft): 300 **Seam Thickness (ft):** 6.8

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	2.9	2.9	3.1	2.7	2.7
Estimated Total Methane Liberated (million cf/day):	0.7	0.6	0.6	0.8	0.7
Emission from Ventilation Systems:	0.7	0.6	0.6	0.8	0.7
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	82	80	75	110	83
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used:

Monterey No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.0	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.4%	0.7%	1.1%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2	0.2

Power Generation Potential

Utility Electric Supplier: Illinois Power Company

Parent Corporation of Utility: Dynergy, Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	25.4	96.0
Mine Electricity Demand:	19.9	76.8
Prep Plant Electricity Demand:	5.5	19.2
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.6	4.8
Assuming 40% Recovery Efficiency:	1.1	9.7
Assuming 60% Recovery Efficiency:	1.7	14.5

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: Irregular/Smooth Plains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Illinois Power

Distance to Pipeline (miles): 1.7 **Pipeline Diameter** 6.0

Owner of Next Nearest Pipeline: Amren CIPS

Distance to Next Nearest Pipeline (miles): 10.0 **Pipeline Diameter** 4"

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Pattiki Mine

GEOGRAPHIC DATA

Basin: Illinois **State:** IL

Coalbed: Herrin No. 6 **County:** White

CORPORATE INFORMATION

Current Owner: White County Coal L.L.C.

Parent Company: Alliance Coal LLC **Parent Company Web Site:**

Previous Owner(s): MAPCO Coal, Inc. **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Mark Kitchen **Phone Number:** (618) 382-4651

Mailing Address: P.O. Box 457

City: Carmi **State:** IL **ZIP** 62821

GENERAL INFORMATION

Number of Employees at Mine: 236 **Mining Method:** Continuous

Year of Initial Production: 1985 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 2.8%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 11,750

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	2.0	2.2	2.3	2.4	2.4
Estimated Total Methane Liberated (million cf/day):	2.1	2.0	2.0	2.5	2.1
Emission from Ventilation Systems:	2.1	2.0	2.0	2.5	2.1
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	378	339	315	375	408
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Pattiki Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.1	0.1	0.2
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.5%	3.0%	4.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.7	1.0

Power Generation Potential

Utility Electric Supplier: Carmi Water & Light Dept.

Parent Corporation of Utility: Municipal Owned

	MW	GWh/year
Total Electricity Demand (2001 data):	15.0	56.7
Mine Electricity Demand:	11.8	45.3
Prep Plant Electricity Demand:	3.2	11.3
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	1.6	14.0
Assuming 40% Recovery Efficiency:	3.2	28.0
Assuming 60% Recovery Efficiency:	4.8	42.0

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.2
Assuming 40% Recovery (Bcf):	0.3
Assuming 60% Recovery (Bcf):	0.5

Description of Surrounding Terrain: Irregular Plains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Texas Eastern Transmission Co.

Distance to Pipeline (miles): 3.3 **Pipeline Diameter** 24.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Rend Lake

GEOGRAPHIC DATA

Basin: Illinois **State:** IL

Coalbed: Herrin No. 6 **County:** Jefferson

CORPORATE INFORMATION

Current Owner: Consolidation Coal Co.

Parent Company: CONSOL Energy **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): Inland Steel **Previous or Alternate Name of Mine:** Inland No. 1

MINE ADDRESS

Contact Name: Ron Fisher **Phone Number:** (618) 625-2071

Mailing Address: P.O. Box 566

City: Sesser **State:** IL **ZIP** 62884

GENERAL INFORMATION

Number of Employees at Mine: NA **Mining Method:** Longwall/Continuous

Year of Initial Production: 1967 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: **Sulfur Content of Coal Produced:** .81% - 1.81%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,000

Depth to Seam (ft): 600 **Seam Thickness (ft):** 7.0 - 9.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	4.1	4.1	3.8	2.7	2.7
Estimated Total Methane Liberated (million cf/day):	1.8	1.9	1.9	2.2	1.5
Emission from Ventilation Systems:	1.8	1.9	1.9	2.2	1.5
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	158	173	188	298	290
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Rend Lake (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.1	0.1	0.2
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.1%	2.1%	3.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.5	0.7

Power Generation Potential

Utility Electric Supplier: Central Illinois Public Service

Parent Corporation of Utility: CIPSCO, Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	15.5	58.5
Mine Electricity Demand:	12.1	46.8
Prep Plant Electricity Demand:	3.3	11.7
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	1.2	10.3
Assuming 40% Recovery Efficiency:	2.3	20.6
Assuming 60% Recovery Efficiency:	3.5	30.9

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.3

Description of Surrounding Terrain: Irregular Plains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Amren CIPS

Distance to Pipeline (miles): 2.5 **Pipeline Diameter** 6.0

Owner of Next Nearest Pipeline: NGPL

Distance to Next Nearest Pipeline (miles): 18.3 **Pipeline Diameter** 30.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Wabash

GEOGRAPHIC DATA

Basin: Illinois

State: IL

Coalbed: Springfield No. 5

County: Wabash

CORPORATE INFORMATION

Current Owner: RAG Midwest Coal Holding Co.

Parent Company: RAG Coal International AG

Parent Company Web Site: http://www.rag-american.com/

Previous Owner(s): Amax Coal Co.

Previous or Alternate Name of Mine: None

MINE ADDRESS

Contact Name: William Kelly, Gen. Mine Mgr.

Phone Number: (618) 298-2394

Mailing Address: P.O. Box 144

City: Keensburg **State:** IL **ZIP** 62852

GENERAL INFORMATION

Number of Employees at Mine: 177

Mining Method: Continuous

Year of Initial Production: 1973

Primary Coal Use: Steam

Life Expectancy:

Sulfur Content of Coal Produced: 1.5%

Prep Plant Located on Site? Yes

BTUs/lb of Coal Produced: 11,000

Depth to Seam (ft): NA

Seam Thickness (ft): NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	1.6	1.4	1.3	1.5	1.5
Estimated Total Methane Liberated (million cf/day):	1.6	0.8	0.8	1.2	1.5
Emission from Ventilation Systems:	1.6	0.8	0.8	1.2	1.5
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	366	205	220	298	382
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Wabash (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.5%	3.0%	4.5%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.7	1.0

Power Generation Potential

Utility Electric Supplier: Wayne White Counties Elec. Coop./Norris Elec. Coop.

Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Total Electricity Demand (2001 data):	11.6	43.9
Mine Electricity Demand:	9.1	35.1
Prep Plant Electricity Demand:	2.5	8.8
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	1.2	10.2
Assuming 40% Recovery Efficiency:	2.3	20.3
Assuming 60% Recovery Efficiency:	3.5	30.5

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.3

Description of Surrounding Terrain: Irregular Plains

Transmission Pipeline in County? No

Owner of Nearest Pipeline: Texas Eastern Transmission Co.

Distance to Pipeline (miles): 4.2 **Pipeline Diameter** 24.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: One of Gassiest Mines in Illinois Basin

6. Profiled Mines (continued)

Indiana Mines

Gibson

Updated: 04/01/2003 **Status:** Active

Gibson

GEOGRAPHIC DATA

Basin: Illinois **State:** IN

Coalbed: Springfield No.5 **County:** Gibson

CORPORATE INFORMATION

Current Owner: Gibson County Coal LLC

Parent Company: Alliance Resources Partners **Parent Company Web Site:** www.arlp.com

Previous Owner(s): Alliance Resources Holdings **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: NA **Phone Number:** (812) 385-1816

Mailing Address: P.O.Box 1269, Route

City: Princeton **State:** IN **ZIP** 47670

GENERAL INFORMATION

Number of Employees at Mine: 153 **Mining Method:** Continuous

Year of Initial Production: 2000 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** NA

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,800

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	0.0	0.0	0.0	0.0	0.0
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.0	0.0	1.3
Emission from Ventilation Systems:	0.0	0.0	0.0	0.0	1.3
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):				0	291
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used:

Gibson (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.0%	2.0%	3.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.5	0.7

Power Generation Potential

Utility Electric Supplier: PSI

Parent Corporation of Utility: Cinergy

	MW	GWh/year
Total Electricity Demand (2001 data):	13.2	50.0
Mine Electricity Demand:	10.4	40.0
Prep Plant Electricity Demand:	2.8	10.0
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	1.0	8.8
Assuming 40% Recovery Efficiency:	2.0	17.7
Assuming 60% Recovery Efficiency:	3.0	26.5

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.3

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Texas Gas Transmission Co.

Distance to Pipeline (miles): < 5.0 **Pipeline Diameter** 4.0

Owner of Next Nearest Pipeline: Texas Eastern Transmission Co.

Distance to Next Nearest Pipeline (miles): < 10.0 **Pipeline Diameter** 20"

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

6. Profiled Mines (continued)

Kentucky Mines

Baker
Camp No. 11
Cardinal No. 2
Clean Energy No. 1
Leeco No. 68
Mine #1
Pontiki No. 2

Updated: 04/01/2003 **Status:** Active

Baker

GEOGRAPHIC DATA

Basin: Illinois **State:** KY

Coalbed: W. Kentucky No. 13 **County:** Webster

CORPORATE INFORMATION

Current Owner: Lodestar Energy, Inc

Parent Company: Lodestar Energy, Inc. **Parent Company Web Site:** www.lodestarenergy.com

Previous Owner(s): The Renco Group **Previous or Alternate Name of Mine:** Pyro/Baker

MINE ADDRESS

Contact Name: David Wineberger, Mine Mgr. **Phone Number:** (270) 664-6677

Mailing Address: P.O. Box 448

City: Clay **State:** KY **ZIP** 42404

GENERAL INFORMATION

Number of Employees at Mine: 390 **Mining Method:** Longwall/Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 1.9% - 3.0%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 9,400

Depth to Seam (ft): 850 **Seam Thickness (ft):** 6.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	4.1	4.4	4.5	4.3	4.3
Estimated Total Methane Liberated (million cf/day):	2.3	2.1	2.2	2.2	3.4
Emission from Ventilation Systems:	2.0	1.9	2.0	2.2	3.4
Estimated Methane Drained:	0.2	0.2	0.2	0.0	0.0
Estimated Specific Emissions (cf/ton):	181	159	161	187	366
Methane Recovered (million cf/day):	0.0	0.0	0.0	0.0	0.0

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Baker (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.1	0.2	0.3
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.7%	3.4%	5.1%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.4%	0.8	1.2

Power Generation Potential

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	MW	GWh/year
Total Electricity Demand (2001 data):	26.7	100.9
Mine Electricity Demand:	20.9	80.7
Prep Plant Electricity Demand:	5.7	20.2
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	2.6	22.4
Assuming 40% Recovery Efficiency:	5.1	44.7
Assuming 60% Recovery Efficiency:	7.7	67.1

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.2
Assuming 40% Recovery (Bcf):	0.5
Assuming 60% Recovery (Bcf):	0.7

Description of Surrounding Terrain: Open Hills

Transmission Pipeline in County? No

Owner of Nearest Pipeline: Texas Gas Transmission

Distance to Pipeline (miles): 8.3 **Pipeline Diameter** 26.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Camp #11

GEOGRAPHIC DATA

Basin: Illinois **State:** KY

Coalbed: W. Kentucky No. 9 **County:** Union

CORPORATE INFORMATION

Current Owner: Peabody Energy

Parent Company: Peabody Energy **Parent Company Web Site:** www.peapodyenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Louis Adams **Phone Number:** (270) 389-1007

Mailing Address: P.O. Box 120

City: Morganfield **State:** KY **ZIP** 42437

GENERAL INFORMATION

Number of Employees at Mine: 300 **Mining Method:** Longwall

Year of Initial Production: 1990 **Primary Coal Use:** Steam

Life Expectancy: NA **Sulfur Content of Coal Produced:** 2.89%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 11,462

Depth to Seam (ft): 350 **Seam Thickness (ft):** 5.2

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	3.5	3.4	3.7	3.8	3.8
Estimated Total Methane Liberated (million cf/day):	0.6	1.0	0.9	1.3	1.0
Emission from Ventilation Systems:	0.6	1.0	0.9	1.3	1.0
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	62	105	88	125	103
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Camp #11 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.4%	0.8%	1.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2	0.3

Power Generation Potential

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	MW	GWh/year
Total Electricity Demand (2001 data):	28.2	106.5
Mine Electricity Demand:	22.1	85.2
Prep Plant Electricity Demand:	6.1	21.3
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.8	6.6
Assuming 40% Recovery Efficiency:	1.5	13.3
Assuming 60% Recovery Efficiency:	2.3	19.9

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: Open Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Texas Gas Transmission Co.

Distance to Pipeline (miles): 4.0 **Pipeline Diameter** 26.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Cardinal No. 2

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** KY

Coalbed: #11 **County:** Hopkins

CORPORATE INFORMATION

Current Owner: Roberts Brothers Coal Co., Inc.

Parent Company: Roberts Brothers Coal Co. Inc. **Parent Company Web Site:**

Previous Owner(s): Warrior Coal **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: NA **Phone Number:** (270) 825-0652

Mailing Address: P.O. Drawer 1210

City: Madisonville **State:** KY **ZIP** 42431

GENERAL INFORMATION

Number of Employees at Mine: NA **Mining Method:** Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:**

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:**

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	1.4	1.7	1.5	1.6	1.6
Estimated Total Methane Liberated (million cf/day):	0.9	0.9	0.4	0.8	0.7
Emission from Ventilation Systems:	0.9	0.9	0.4	0.8	0.7
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	221	188	112	177	133
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used:

Cardinal No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.0	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:			

BTU Value of Recovered Methane/BTU Value of Coal Produced:

Power Generation Potential

Utility Electric Supplier: Kenergy Corp

Parent Corporation of Utility: Touchstone Energy Cooperatives

	MW	GWh/year
Total Electricity Demand (2001 data):	15.2	57.7
Mine Electricity Demand:	12.0	46.1
Prep Plant Electricity Demand:	3.3	11.5
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.5	4.6
Assuming 40% Recovery Efficiency:	1.1	9.3
Assuming 60% Recovery Efficiency:	1.6	13.9

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: ANR Pipeline Company

Distance to Pipeline (miles): < 3.0 **Pipeline Diameter** 30.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Clean Energy No. 1

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** KY

Coalbed: Pond Creek **County:** Pike

CORPORATE INFORMATION

Current Owner: Massey Energy Co.

Parent Company: Massey Energy Co. **Parent Company Web Site:** www.masseyenergyco.com

Previous Owner(s): Sidney Coal Co., Clean **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Barry Dotson **Phone Number:** (60) 635-3720

Mailing Address: 29501 Mayo Trail

City: Sidney **State:** KY **ZIP** 41564

GENERAL INFORMATION

Number of Employees at Mine: **Mining Method:** Continuous

Year of Initial Production: 1994 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: **Sulfur Content of Coal Produced:** NA

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,200

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	1.2	1.3	1.2	1.1	1.1
Estimated Total Methane Liberated (million cf/day):	0.5	1.1	1.2	1.0	0.9
Emission from Ventilation Systems:	0.5	1.1	1.2	1.0	0.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	144	308	377	332	231
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Clean Energy No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.8%	1.5%	2.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.4	0.5

Power Generation Potential

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	MW	GWh/year
Total Electricity Demand (2001 data):	10.6	40.2
Mine Electricity Demand:	8.3	32.2
Prep Plant Electricity Demand:	2.3	8.0
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.6	5.6
Assuming 40% Recovery Efficiency:	1.3	11.3
Assuming 60% Recovery Efficiency:	1.9	16.9

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas of Kentucky, Inc.

Distance to Pipeline (miles): < 2.0 **Pipeline Diameter** 10.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Leeco No. 68

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** KY

Coalbed: Aberdeen **County:** Perry

CORPORATE INFORMATION

Current Owner: Leeco, Inc.

Parent Company: James River Coal Co. **Parent Company Web Site:** www.jamesrivercoal.com

Previous Owner(s): Transco Coal Co. **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Jack Holbrook **Phone Number:** (606) 439-3075

Mailing Address: P.O. Box 309

City: Cornettsville **State:** KY **ZIP** 41751

GENERAL INFORMATION

Number of Employees at Mine: NA **Mining Method:** Continuous

Year of Initial Production: 1995 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 0.8%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,250

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	1.5	1.5	1.4	1.2	1.2
Estimated Total Methane Liberated (million cf/day):	0.3	0.4	0.5	0.5	0.7
Emission from Ventilation Systems:	0.3	0.4	0.5	0.5	0.7
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	70	108	128	139	201
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used:

Leeco No. 68 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.0	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.7%	1.3%	2.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.3	0.5

Power Generation Potential

Utility Electric Supplier: Kentucky Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	9.5	36.0
Mine Electricity Demand:	7.5	28.8
Prep Plant Electricity Demand:	2.0	7.2
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.5	4.4
Assuming 40% Recovery Efficiency:	1.0	8.8
Assuming 60% Recovery Efficiency:	1.5	13.1

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.0
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.1

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Kentucky West Virginia Gas Co.

Distance to Pipeline (miles): < 2.0 **Pipeline Diameter** 6.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Mine #1

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** KY

Coalbed: Pond Creek **County:** Pike

CORPORATE INFORMATION

Current Owner: Aero Energy Co. Inc.

Parent Company: Aero Energy Co. Inc. **Parent Company Web Site:**

Previous Owner(s): Freedom Energy Mining Co. **Previous or Alternate Name of Mine:** Mine No. 1

MINE ADDRESS

Contact Name: Jonah Varney **Phone Number:** (606) 353-0067

Mailing Address: P.O. Box 299

City: Sydney **State:** KY **ZIP** 41564

GENERAL INFORMATION

Number of Employees at Mine: NA **Mining Method:** Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: **Sulfur Content of Coal Produced:** 1.67%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,822

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	1.1	1.2	1.5	1.5	1.5
Estimated Total Methane Liberated (million cf/day):	0.4	0.8	1.1	1.1	1.0
Emission from Ventilation Systems:	0.4	0.8	1.1	1.1	1.0
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	140	235	257	281	202
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Mine #1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.7%	1.4%	2.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.3	0.5

Power Generation Potential

Utility Electric Supplier: Kentucky Utilities Co.

Parent Corporation of Utility: KU Energy

	MW	GWh/year
Total Electricity Demand (2001 data):	15.1	57.0
Mine Electricity Demand:	11.8	45.6
Prep Plant Electricity Demand:	3.2	11.4
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.8	7.0
Assuming 40% Recovery Efficiency:	1.6	13.9
Assuming 60% Recovery Efficiency:	2.4	20.9

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain: Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas of Kentucky, Inc.

Distance to Pipeline (miles): < 2.0 **Pipeline Diameter** 10.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Pontiki No. 2

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** KY

Coalbed: Pond Creek **County:** Martin

CORPORATE INFORMATION

Current Owner: Excel Mining LLC

Parent Company: Excel Mining **Parent Company Web Site:**

Previous Owner(s): Pontiki Coal Co. **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: John Small **Phone Number:** (606) 395-5352

Mailing Address: P.O. Box 802

City: Lovely **State:** KY **ZIP** 41231

GENERAL INFORMATION

Number of Employees at Mine: **Mining Method:** Continuous

Year of Initial Production: **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 0.6% - 0.73%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,900

Depth to Seam (ft): 425 **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	0.9	0.7	0.8	0.6	0.6
Estimated Total Methane Liberated (million cf/day):	0.0	0.3	0.6	0.5	0.6
Emission from Ventilation Systems:	0.0	0.3	0.6	0.5	0.6
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	0	151	283	335	182
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Pontiki No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.0	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.6%	1.2%	1.8%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.3	0.4

Power Generation Potential

Utility Electric Supplier: Kentucky Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	9.4	35.5
Mine Electricity Demand:	7.4	28.4
Prep Plant Electricity Demand:	2.0	7.1
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.4	3.9
Assuming 40% Recovery Efficiency:	0.9	7.8
Assuming 60% Recovery Efficiency:	1.3	11.7

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.0
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.1

Description of Surrounding Terrain: High Hills/Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): 2.0 **Pipeline Diameter** 6.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments:

6. Profiled Mines (continued)

New Mexico Mines

San Juan South

Updated: 04/01/2003 **Status:** Active

San Juan South

GEOGRAPHIC DATA

Basin: San Juan **State:** NM

Coalbed: No 9, No. 8 **County:** San Juan

CORPORATE INFORMATION

Current Owner: San Juan Coal Co.

Parent Company: BHP Billiton **Parent Company Web Site:** www.bhpbilliton.com

Previous Owner(s): **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Scott Langley **Phone Number:** (505) 598-2000

Mailing Address: P.O. Box 561

City: Waterflow **State:** NM **ZIP** 87421

GENERAL INFORMATION

Number of Employees at Mine: 280 **Mining Method:** Longwall

Year of Initial Production: 1997 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 0.8%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 9,500

Depth to Seam (ft): 300 - 1,000 **Seam Thickness (ft):** 4.2 - 14.6

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	0.0	0.2	0.1	0.0	0.0
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.0	0.0	0.3
Emission from Ventilation Systems:	0.0	0.0	0.0	0.0	0.3
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):		0	0	0	166
Methane Recovered (million cf/day):	0.0	0.0	0.0	0.0	0.0

Estimated Current Drainage Efficiency: 0%

Drainage System Used: Vertical Gob, Horizontal Pre-mine

San Juan South (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.0	0.0
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.8%	1.5%	2.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.4	0.5

Power Generation Potential

Utility Electric Supplier: Public Service of New Mexico

Parent Corporation of Utility: Public Service of New Mexico

	MW	GWh/year
Total Electricity Demand (2001 data):	5.4	20.4
Mine Electricity Demand:	4.2	16.3
Prep Plant Electricity Demand:	1.2	4.1
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.2	2.1
Assuming 40% Recovery Efficiency:	0.5	4.1
Assuming 60% Recovery Efficiency:	0.7	6.2

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.0
Assuming 40% Recovery (Bcf):	0.0
Assuming 60% Recovery (Bcf):	0.1

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Western/Chuska

Distance to Pipeline (miles): < 10.0 **Pipeline Diameter** 16.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments: Recently Began Underground Mining Operations

Ohio Mines

Cadiz Portal
Powhatan No. 6

Updated: 04/01/2003 **Status:** Active

Cadiz Portal

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** OH

Coalbed: Lower Freeport **County:** Harrison

CORPORATE INFORMATION

Current Owner: AEP Coal, Inc.

Parent Company: American Electric Power **Parent Company Web Site:** www.aep.com

Previous Owner(s): Harrison Mining Corp. **Previous or Alternate Name of Mine:** Nelms Cadiz Portal

MINE ADDRESS

Contact Name: Bruce Hann **Phone Number:** (659) 335-6906

Mailing Address: 44961 Old Hopedale

City: Cadiz **State:** OH **ZIP** 43907

GENERAL INFORMATION

Number of Employees at Mine: 223 **Mining Method:** Continuous

Year of Initial Production: 1990 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 2.4%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,050

Depth to Seam (ft): 520 **Seam Thickness (ft):** 5.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	1.4	1.4	1.2	1.7	1.7
Estimated Total Methane Liberated (million cf/day):	0.8	0.8	0.7	0.9	0.8
Emission from Ventilation Systems:	0.8	0.8	0.7	0.9	0.8
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	201	193	207	179	174
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used:

Cadiz Portal (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.6%	1.2%	1.8%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.3	0.4

Power Generation Potential

Utility Electric Supplier: Ohio Edison

Parent Corporation of Utility: FirstEnergy Corp.

	MW	GWh/year
Total Electricity Demand (2001 data):	13.6	51.6
Mine Electricity Demand:	10.7	41.3
Prep Plant Electricity Demand:	2.9	10.3
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.6	5.4
Assuming 40% Recovery Efficiency:	1.2	10.9
Assuming 60% Recovery Efficiency:	1.9	16.3

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): **Pipeline Diameter** 8.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Powhatan No. 6 Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** OH

Coalbed: Pittsburgh No. 8 **County:** Belmont

CORPORATE INFORMATION

Current Owner: Ohio Valley Coal Co.

Parent Company: Ohio Valley Coal Company **Parent Company Web Site:** www.ohiovalleycoal.com

Previous Owner(s): None in last ten years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: John Forrelli **Phone Number:** (740) 926-1351

Mailing Address: 56854 Pleasant Ridge

City: Alledonia **State:** OH **ZIP** 43902

GENERAL INFORMATION

Number of Employees at Mine: 440

Mining Method: Longwall/Continuous

Year of Initial Production: 1972

Primary Coal Use: Steam

Life Expectancy:

Sulfur Content of Coal Produced: 3.8% - 4.5%

Prep Plant Located on Site? Yes

BTUs/lb of Coal Produced: 12,600

Depth to Seam (ft): 270

Seam Thickness (ft): 5.3

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	5.1	4.3	4.4	4.6	4.6
Estimated Total Methane Liberated (million cf/day):	1.3	1.5	1.0	1.1	1.4
Emission from Ventilation Systems:	1.3	1.5	1.0	1.1	1.4
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	94	133	84	89	114
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Powhatan No. 6 Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.4%	0.8%	1.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2	0.3

Power Generation Potential

Utility Electric Supplier: The Dayton Power & Light Co.

Parent Corporation of Utility: DPL Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	36.6	138.3
Mine Electricity Demand:	28.7	110.7
Prep Plant Electricity Demand:	7.9	27.7
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	1.1	9.6
Assuming 40% Recovery Efficiency:	2.2	19.1
Assuming 60% Recovery Efficiency:	3.3	28.7

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.3

Description of Surrounding Terrain: Hills/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): 0.1 **Pipeline Diameter** 4.0

Owner of Next Nearest Pipeline: Texas Eastern Transmission

Distance to Next Nearest Pipeline (miles): 1.4 **Pipeline Diameter** 30.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments:

Oklahoma Mines

Pollyanna No. 8

Updated: 04/01/2003 **Status:** Active

Pollyanna No. 8

GEOGRAPHIC DATA

Basin: Arkoma **State:** OK

Coalbed: Hartshorne **County:** Le Flore

CORPORATE INFORMATION

Current Owner: HMI

Parent Company: HMI **Parent Company Web Site:**

Previous Owner(s): Sunrise Coal **Previous or Alternate Name of Mine:** Sunrise Coal

MINE ADDRESS

Contact Name: **Phone Number:** (918) 962-9400

Mailing Address: P. O. Box 550

City: Henryetta **State:** OK **ZIP** 74437

GENERAL INFORMATION

Number of Employees at Mine: **Mining Method:** Continuous

Year of Initial Production: 1995 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** NA

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 14,100

Depth to Seam (ft): NA **Seam Thickness (ft):**

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	0.2	0.2	0.2	0.2	0.2
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.0	0.5	0.9
Emission from Ventilation Systems:	0.0	0.0	0.0	0.5	0.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	0	0	0	787	827
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used:

Pollyanna No. 8 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	2.5%	5.1%	7.6%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.6%	1.2	1.8

Power Generation Potential

Utility Electric Supplier: OGE Energy Corp

Parent Corporation of Utility: OGE Energy Corp.

	MW	GWh/year
Total Electricity Demand (2001 data):	3.3	12.4
Mine Electricity Demand:	2.6	10.0
Prep Plant Electricity Demand:	0.7	2.5
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.7	6.2
Assuming 40% Recovery Efficiency:	1.4	12.5
Assuming 60% Recovery Efficiency:	2.1	18.7

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Arkansas Oklahoma Gas Co.

Distance to Pipeline (miles): 2.0 **Pipeline Diameter** 6.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Pennsylvania Mines

Bailey
Cumberland
Eighty-Four Mine
Emerald
Enlow Fork

Updated: 04/01/2003 **Status:** Active

Bailey Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** PA

Coalbed: Pittsburgh **County:** Greene

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: Consol Energy Inc. **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Roy Pride **Phone Number:** (724) 663-4781

Mailing Address: 332 Enon Church

City: Graysville **State:** PA **ZIP** 15337

GENERAL INFORMATION

Number of Employees at Mine: NA **Mining Method:** Longwall/Continuous

Year of Initial Production: 1984 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: **Sulfur Content of Coal Produced:** 1.03% -2.41%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 13,200

Depth to Seam (ft): 800 **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	7.5	8.3	8.5	9.9	9.9
Estimated Total Methane Liberated (million cf/day):	11.5	11.7	8.6	7.6	6.8
Emission from Ventilation Systems:	6.9	7.0	6.9	7.6	6.7
Estimated Methane Drained:	4.6	4.7	1.7	0.1	0.1
Estimated Specific Emissions (cf/ton):	336	308	297	279	238
Methane Recovered (million cf/day):	0.0	0.0	0.0	0.0	0.0

Estimated Current Drainage Efficiency: 1%

Drainage System Used: Vertical Gob

Bailey Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.2	0.4	0.7
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.8%	1.6%	2.4%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.4	0.5

Power Generation Potential

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	81.9	309.8
Mine Electricity Demand:	64.3	247.9
Prep Plant Electricity Demand:	17.6	62.0
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	5.2	45.3
Assuming 40% Recovery Efficiency:	10.3	90.7
Assuming 60% Recovery Efficiency:	15.5	136.0

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.5
Assuming 40% Recovery (Bcf):	1.0
Assuming 60% Recovery (Bcf):	1.5

Description of Surrounding Terrain: High Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Carnegie Natural Gas

Distance to Pipeline (miles): 6.0 **Pipeline Diameter** 20.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Cumberland Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** PA

Coalbed: Pittsburgh No. 8 **County:** Greene

CORPORATE INFORMATION

Current Owner: RAG Cumberland Resources, LP

Parent Company: RAG American Coal Co. **Parent Company Web Site:** http://www.rag-american.com/

Previous Owner(s): Cyprus Amax, U. S. Steel **Previous or Alternate Name of Mine:** Cumberland

MINE ADDRESS

Contact Name: Sam Cario **Phone Number:** (724) 852-5845

Mailing Address: 145 Elm Dr.

City: Waynesburg **State:** PA **ZIP** 15370

GENERAL INFORMATION

Number of Employees at Mine: 557 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1972 **Primary Coal Use:** Steam

Life Expectancy: 2023 **Sulfur Content of Coal Produced:** 2.4%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 13,000

Depth to Seam (ft): 900 **Seam Thickness (ft):** 6.5 - 7.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	6.3	6.3	6.6	6.5	6.5
Estimated Total Methane Liberated (million cf/day):	11.3	11.4	10.7	17.4	16.2
Emission from Ventilation Systems:	9.6	9.7	9.1	12.9	11.7
Estimated Methane Drained:	1.7	1.7	1.6	4.5	4.5
Estimated Specific Emissions (cf/ton):	554	563	505	721	641
Methane Recovered (million cf/day):	0.0	0.0	0.0	0.0	0.0

Estimated Current Drainage Efficiency: 28%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Cumberland Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.5	1.1	1.6
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	3.0%	5.9%	8.9%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.7%	1.4	2.0

Power Generation Potential

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	52.8	199.6
Mine Electricity Demand:	41.4	159.7
Prep Plant Electricity Demand:	11.3	39.9
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	12.3	107.4
Assuming 40% Recovery Efficiency:	24.5	214.9
Assuming 60% Recovery Efficiency:	36.8	322.3

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	1.2
Assuming 40% Recovery (Bcf):	2.4
Assuming 60% Recovery (Bcf):	3.5

Description of Surrounding Terrain: High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Texas Eastern Transmission Co.

Distance to Pipeline (miles): 0.2 **Pipeline Diameter** 24.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Eighty-Four Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** PA

Coalbed: Pittsburgh **County:** Washington

CORPORATE INFORMATION

Current Owner: Eighty-Four Mining Co.

Parent Company: Consol Energy Inc. **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): Beth Energy Mines **Previous or Alternate Name of Mine:** Ellsworth or Livingston

MINE ADDRESS

Contact Name: Eric Schubel **Phone Number:** (724) 250-1577

Mailing Address: P.O. Box 284

City: Eighty Four **State:** PA **ZIP** 15330

GENERAL INFORMATION

Number of Employees at Mine: NA **Mining Method:** Longwall/Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: **Sulfur Content of Coal Produced:** 1.33% - 1.71%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,307

Depth to Seam (ft): 625 **Seam Thickness (ft):** 7.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	4.8	5.9	5.8	4.2	4.2
Estimated Total Methane Liberated (million cf/day):	9.1	6.5	6.0	6.1	4.6
Emission from Ventilation Systems:	9.1	6.5	6.0	6.1	4.6
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	695	398	379	531	1022
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Eighty-Four Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.1	0.3	0.4
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	3.3%	6.6%	10.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.8%	1.5	2.3

Power Generation Potential

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	13.1	49.5
Mine Electricity Demand:	10.3	39.6
Prep Plant Electricity Demand:	2.8	9.9
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	3.5	30.7
Assuming 40% Recovery Efficiency:	7.0	61.3
Assuming 60% Recovery Efficiency:	10.5	92.0

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.3
Assuming 40% Recovery (Bcf):	0.7
Assuming 60% Recovery (Bcf):	1.0

Description of Surrounding Terrain: Open High Hills/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas of Pennsylvania, Inc.

Distance to Pipeline (miles): 6.0 **Pipeline Diameter** 20.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Emerald Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** PA

Coalbed: Pittsburgh No. 8 **County:** Greene

CORPORATE INFORMATION

Current Owner: RAG Emerald Resources, LP

Parent Company: RAG American Coal Co. **Parent Company Web Site:** http://www.rag-american.com/

Previous Owner(s): Cyprus Amax **Previous or Alternate Name of Mine:** Emerald No. 1

MINE ADDRESS

Contact Name: D.M. Conklin **Phone Number:** (724) 852-1200

Mailing Address: 145 Elm Dr., P. O. Box

City: Waynesburg **State:** PA **ZIP** 15370

GENERAL INFORMATION

Number of Employees at Mine: 484 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1977 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: 2013 **Sulfur Content of Coal Produced:** 2.4%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 13,000

Depth to Seam (ft): 650 **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	4.7	5.4	4.3	6.4	6.4
Estimated Total Methane Liberated (million cf/day):	9.3	9.4	8.3	7.5	7.6
Emission from Ventilation Systems:	5.6	5.7	5.0	5.8	5.9
Estimated Methane Drained:	3.7	3.8	3.3	1.6	1.7
Estimated Specific Emissions (cf/ton):	428	385	418	332	317
Methane Recovered (million cf/day):	0.0	0.0	0.0	0.0	0.0

Estimated Current Drainage Efficiency: 22%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Emerald Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.2	0.5	0.7
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.4%	2.7%	4.1%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6	0.9

Power Generation Potential

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	53.4	202.1
Mine Electricity Demand:	41.9	161.7
Prep Plant Electricity Demand:	11.5	40.4
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	5.7	50.2
Assuming 40% Recovery Efficiency:	11.5	100.3
Assuming 60% Recovery Efficiency:	17.2	150.5

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.6
Assuming 40% Recovery (Bcf):	1.1
Assuming 60% Recovery (Bcf):	1.7

Description of Surrounding Terrain: High Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Texas Eastern Transmission Co.

Distance to Pipeline (miles): 0.2 **Pipeline Diameter** 24.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Enlow Fork Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** PA

Coalbed: Pittsburgh **County:** Greene

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: Consol Energy Inc. **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Dave Hudson **Phone Number:** (724) 663-7501

Mailing Address: 322 Enon Church Rd.

City: West Finley **State:** PA **ZIP** 15377

GENERAL INFORMATION

Number of Employees at Mine: NA **Mining Method:** Longwall/Continuous

Year of Initial Production: 1990 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 1.00% -2.41%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,000

Depth to Seam (ft): 800 **Seam Thickness (ft):** 5.7 - 6.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	8.4	8.8	9.8	9.5	9.5
Estimated Total Methane Liberated (million cf/day):	16.1	19.9	13.9	11.1	9.8
Emission from Ventilation Systems:	9.7	11.9	11.1	11.0	9.7
Estimated Methane Drained:	6.4	8.0	2.8	0.1	0.1
Estimated Specific Emissions (cf/ton):	422	495	411	422	343
Methane Recovered (million cf/day):	0.0	0.0	0.0	0.0	0.0

Estimated Current Drainage Efficiency: 1%

Drainage System Used: Vertical Gob

Enlow Fork Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.3	0.6	1.0
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.1%	2.3%	3.4%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.5	0.8

Power Generation Potential

Utility Electric Supplier: West Penn Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	81.9	309.8
Mine Electricity Demand:	64.3	247.8
Prep Plant Electricity Demand:	17.6	62.0
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	7.4	64.9
Assuming 40% Recovery Efficiency:	14.8	129.8
Assuming 60% Recovery Efficiency:	22.2	194.7

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.7
Assuming 40% Recovery (Bcf):	1.4
Assuming 60% Recovery (Bcf):	2.1

Description of Surrounding Terrain: Open Hills/Open High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): 6.0 **Pipeline Diameter** 20.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

6. Profiled Mines (continued)

Utah Mines

Aberdeen
Dugout
Pinnacle
West Ridge

Updated: 04/01/2003 **Status:** Active

Aberdeen

GEOGRAPHIC DATA

Basin: Uinta **State:** UT

Coalbed: L. Sunnyside, Gilson, And Aberdeen **County:** Carbon

CORPORATE INFORMATION

Current Owner: Andalex Resources, Inc.

Parent Company: Andalex Resources, Inc. **Parent Company Web Site:** www.andalex.com

Previous Owner(s): None **Previous or Alternate Name of Mine:** Tower Division

MINE ADDRESS

Contact Name: Garth Neilsen **Phone Number:** (435) 637-5385

Mailing Address: P.O. Box 902

City: Price **State:** UT **ZIP** 84501

GENERAL INFORMATION

Number of Employees at Mine: 31 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1980 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** NA

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 11,991

Depth to Seam (ft): NA **Seam Thickness (ft):** 6.0 - 8.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	1.9	1.8	1.5	1.6	1.6
Estimated Total Methane Liberated (million cf/day):	2.4	2.0	4.4	4.4	1.2
Emission from Ventilation Systems:	2.4	2.0	4.4	4.4	1.2
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	478	412	1037	1020	848
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Aberdeen (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	3.1%	6.2%	9.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.7%	1.4	2.1

Power Generation Potential

Utility Electric Supplier: Price City Utilities, Utah Power & Light

Parent Corporation of Utility: PacifiCorp

	MW	GWh/year
Total Electricity Demand (2001 data):	4.2	16.0
Mine Electricity Demand:	3.3	12.8
Prep Plant Electricity Demand:	0.9	3.2
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.9	8.2
Assuming 40% Recovery Efficiency:	1.9	16.5
Assuming 60% Recovery Efficiency:	2.8	24.7

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.3

Description of Surrounding Terrain: Tablelands; Open High/Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Questar Pipeline Company

Distance to Pipeline (miles): ~5.0 **Pipeline Diameter** 20.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Carbon **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Dugout Canyon Mine

GEOGRAPHIC DATA

Basin: Uinta **State:** UT

Coalbed: Gilson, Rock Canyon **County:** Carbon

CORPORATE INFORMATION

Current Owner: Canyon Fuel Co., LLC

Parent Company: Arch Coal Co. **Parent Company Web Site:** www.archcoal.com

Previous Owner(s): **Previous or Alternate Name of Mine:**

MINE ADDRESS

Contact Name: R.W. Olsen, Mine Mgr. **Phone Number:** (435) 636-2860

Mailing Address: P.O. Box 1029

City: Wellington **State:** UT **ZIP** 84542

GENERAL INFORMATION

Number of Employees at Mine: 175 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1998 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 0.4% - 0.75%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 11,700

Depth to Seam (ft): 1400 **Seam Thickness (ft):** 7.5 - 8.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	0.0	0.2	0.8	0.5	0.5
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.1	0.1	0.6
Emission from Ventilation Systems:	0.0	0.0	0.1	0.1	0.6
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):		0	62	103	103
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used:

Dugout Canyon Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.0	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.4%	0.8%	1.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2	0.3

Power Generation Potential

Utility Electric Supplier: PacifiCorp

Parent Corporation of Utility: PacifiCorp

	MW	GWh/year
Total Electricity Demand (2001 data):	15.7	59.4
Mine Electricity Demand:	12.3	47.5
Prep Plant Electricity Demand:	3.4	11.9
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.4	3.7
Assuming 40% Recovery Efficiency:	0.8	7.4
Assuming 60% Recovery Efficiency:	1.3	11.1

Pipeline Sales Potential

	Bcf
Potential Annual Gas Sales (2001 data)	
Assuming 20% Recovery (Bcf):	0.0
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.1

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Questar Pipeline Company

Distance to Pipeline (miles): < 5.0 **Pipeline Diameter** 20.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Pinnacle

GEOGRAPHIC DATA

Basin: Uinta **State:** UT

Coalbed: L. Sunnyside, Gilson, And Aberdeen **County:** Carbon

CORPORATE INFORMATION

Current Owner: Andalex Resources, Inc.

Parent Company: Andalex Resources, Inc. **Parent Company Web Site:** www.andalex.com

Previous Owner(s): **Previous or Alternate Name of Mine:** Tower Division

MINE ADDRESS

Contact Name: Garth Neilsen **Phone Number:** (435) 637-5385

Mailing Address: P.O. Box 902

City: Price **State:** UT **ZIP** 84501

GENERAL INFORMATION

Number of Employees at Mine: NA **Mining Method:** Longwall/Continuous

Year of Initial Production: 1980 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** NA

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,000

Depth to Seam (ft): NA **Seam Thickness (ft):** 6.0 - 8.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	0.0	0.0	0.1	0.0	0.0
Estimated Total Methane Liberated (million cf/day):	1.0	1.4	0.5	0.5	0.3
Emission from Ventilation Systems:	1.0	1.4	0.5	0.5	0.3
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):			3264	2775	383
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used:

Pinnacle (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.0	0.0
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.4%	2.8%	4.2%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6	1.0

Power Generation Potential

Utility Electric Supplier: PacifiCorp

Parent Corporation of Utility: PacifiCorp

	MW	GWh/year
Total Electricity Demand (2001 data):	2.3	8.9
Mine Electricity Demand:	1.8	7.1
Prep Plant Electricity Demand:	0.5	1.8
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.2	2.1
Assuming 40% Recovery Efficiency:	0.5	4.1
Assuming 60% Recovery Efficiency:	0.7	6.2

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.0
Assuming 40% Recovery (Bcf):	0.0
Assuming 60% Recovery (Bcf):	0.1

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Questar Pipeline Co.

Distance to Pipeline (miles): ~10.0 **Pipeline Diameter** 20.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

West Ridge Mine

GEOGRAPHIC DATA

Basin: Uinta **State:** UT

Coalbed: Lower Sunnyside **County:** Carbon

CORPORATE INFORMATION

Current Owner: West Ridge Resources

Parent Company: Andalex Resources, Inc. **Parent Company Web Site:** www.andalex.com/westridge.html

Previous Owner(s): **Previous or Alternate Name of Mine:**

MINE ADDRESS

Contact Name: Gary Gray **Phone Number:** (435) 564-4015

Mailing Address: P.O. Box 1077

City: Price **State:** UT **ZIP** 84501

GENERAL INFORMATION

Number of Employees at Mine: 76 **Mining Method:** Longwall

Year of Initial Production: 2001 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:**

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,000

Depth to Seam (ft): 1200 **Seam Thickness (ft):**

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	0.0	0.0	0.0	0.5	0.5
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.0	0.0	0.8
Emission from Ventilation Systems:	0.0	0.0	0.0	0.0	0.8
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):			0	0	120
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used:

West Ridge Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.0	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.4%	0.9%	1.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2	0.3

Power Generation Potential

Utility Electric Supplier: PacifiCorp

Parent Corporation of Utility: PacifiCorp

	MW	GWh/year
Total Electricity Demand (2001 data):	18.2	68.7
Mine Electricity Demand:	14.3	55.0
Prep Plant Electricity Demand:	3.9	13.7
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.6	5.0
Assuming 40% Recovery Efficiency:	1.1	10.0
Assuming 60% Recovery Efficiency:	1.7	14.9

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Questar Pipeline Co.

Distance to Pipeline (miles): < 10.0 **Pipeline Diameter** 20.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

6. Profiled Mines (continued)

Virginia Mines

Buchanan
Tiller No. 1
VP No. 8

Updated: 04/01/2003 **Status:** Active

Buchanan Mine

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** VA

Coalbed: Pocahantas No. 3 **County:** Buchanan

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: Consol Energy Inc. **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** Buchanan No. 1

MINE ADDRESS

Contact Name: Terry Suder **Phone Number:** (276) 498-6921

Mailing Address: P.O. Box 230, Rte 632

City: Mavisdale **State:** VA **ZIP** 24627

GENERAL INFORMATION

Number of Employees at Mine:

Mining Method: Longwall/Continuous

Year of Initial Production: 1983

Primary Coal Use: Steam, Metallurgical

Life Expectancy:

Sulfur Content of Coal Produced: 0.73%

Prep Plant Located on Site? Yes

BTUs/lb of Coal Produced: 13,831

Depth to Seam (ft): NA

Seam Thickness (ft): 5.4

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	4.3	4.3	4.7	4.5	4.5
Estimated Total Methane Liberated (million cf/day):	41.3	30.8	19.5	21.6	17.9
Emission from Ventilation Systems:	12.6	12.6	12.3	11.8	10.3
Estimated Methane Drained:	28.8	18.2	7.2	9.8	7.5
Estimated Specific Emissions (cf/ton):	1055	1068	959	963	846
Methane Recovered (million cf/day):	26.9	17.4	7.0	9.8	7.4

Estimated Current Drainage Efficiency: 42%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

Buchanan Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.6	1.2	1.7
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	4.6%	9.1%	13.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.1%	2.1	3.2

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	35.3	133.6
Mine Electricity Demand:	27.7	106.9
Prep Plant Electricity Demand:	7.6	26.7
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	13.5	118.5
Assuming 40% Recovery Efficiency:	27.0	236.9
Assuming 60% Recovery Efficiency:	40.6	355.4

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	1.3
Assuming 40% Recovery (Bcf):	2.6
Assuming 60% Recovery (Bcf):	3.9

Description of Surrounding Terrain: Open Low Mountains/Low Mountains

Transmission Pipeline in County? No

Owner of Nearest Pipeline: Mine owns pipeline that connects to dist. line

Distance to Pipeline (miles): 0.0 **Pipeline Diameter** NA

Owner of Next Nearest Pipeline: Consolidated Natural Gas Supply Co. (CNG)

Distance to Next Nearest Pipeline (miles): 1.0 **Pipeline Diameter** 8.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Ongoing CBM/CMM Program Since Early 1990's

Updated: 04/01/2003 **Status:** Active

Tiller No. 1

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** VA

Coalbed: Tiller **County:** Tazewell

CORPORATE INFORMATION

Current Owner: Knox Creek Coal Corp.

Parent Company: Massey Energy Co. **Parent Company Web Site:** www.masseyenergyco.com

Previous Owner(s): **Previous or Alternate Name of Mine:** Tiller No. 2

MINE ADDRESS

Contact Name: David Kramer, Pres. **Phone Number:** (276) 963-7338

Mailing Address: P.O. Box 519

City: Raven **State:** VA **ZIP** 24639

GENERAL INFORMATION

Number of Employees at Mine: 66 **Mining Method:** Continuous

Year of Initial Production: 1995 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** NA

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 14,000

Depth to Seam (ft): 120 - 270 **Seam Thickness (ft):** 6.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	0.1	0.1	0.2	0.3	0.3
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.0	0.2	0.6
Emission from Ventilation Systems:	0.0	0.0	0.0	0.2	0.6
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	0	0	0	237	397
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used:

Tiller No. 1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.0	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.2%	2.4%	3.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6	0.9

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	4.4	16.6
Mine Electricity Demand:	3.4	13.2
Prep Plant Electricity Demand:	0.9	3.3
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.5	4.0
Assuming 40% Recovery Efficiency:	0.9	8.0
Assuming 60% Recovery Efficiency:	1.4	11.9

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.0
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.1

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: CNG Energy

Distance to Pipeline (miles): < 4.0 **Pipeline Diameter** 8.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

VP No. 8

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** VA

Coalbed: Pocahontas No. 3 **County:** Buchanan

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: Consol Energy Inc. **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 5 years **Previous or Alternate Name of Mine:** VP No. 8

MINE ADDRESS

Contact Name: Neil Made **Phone Number:** (276) 498-7800

Mailing Address: Drawer L

City: Oakwood **State:** VA **ZIP** 24631

GENERAL INFORMATION

Number of Employees at Mine: NA **Mining Method:** Longwall/Continuous

Year of Initial Production: 1994 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: **Sulfur Content of Coal Produced:** 0.75%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 14,013

Depth to Seam (ft): 2050 **Seam Thickness (ft):** 5.0 -5.1

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	1.3	2.7	1.4	2.3	2.3
Estimated Total Methane Liberated (million cf/day):	18.7	48.4	53.7	59.8	70.6
Emission from Ventilation Systems:	8.1	10.2	6.2	7.9	7.3
Estimated Methane Drained:	10.5	38.2	47.5	51.8	63.3
Estimated Specific Emissions (cf/ton):	2246	1361	1667	1284	1150
Methane Recovered (million cf/day):	18.7	37.0	46.3	51.5	63.0

Estimated Current Drainage Efficiency: 90%

Drainage System Used: Vertical Pre-Mine, Vertical Gob, Horizontal Pre-Mine

VP No. 8 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	2.3	4.6	6.9
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	34.0%	68.1%	102.1 %
BTU Value of Recovered Methane/BTU Value of Coal Produced:	7.9%	15.8%	23.7%

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	18.5	69.9
Mine Electricity Demand:	14.5	55.9
Prep Plant Electricity Demand:	4.0	14.0
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	53.5	468.5
Assuming 40% Recovery Efficiency:	107.0	937.1
Assuming 60% Recovery Efficiency:	160.5	1405.0

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	5.2
Assuming 40% Recovery (Bcf):	10.3
Assuming 60% Recovery (Bcf):	15.5

Description of Surrounding Terrain: Open Low Mountains/Low Mountains

Transmission Pipeline in County? No

Owner of Nearest Pipeline: Mine owns pipeline that connects to dist. line

Distance to Pipeline (miles): 0.0 **Pipeline Diameter** NA

Owner of Next Nearest Pipeline: Consolidated Natural Gas Supply Co. (CNG)

Distance to Next Nearest Pipeline (miles): 1.0 **Pipeline Diameter** 6.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Ongoing CBM/CMM Program Since Early 1990's

6. Profiled Mines (continued)

West Virginia Mines

Blacksville No. 2
Federal No. 2
Harris No. 1
Justice #1
Loverage No. 22
McElroy
U.S. Steel No. 50
Robinson Run No. 95
Sentinel
Shoemaker
Whitetail Kittanning
Upper Big Branch - South

Updated: 04/01/2003 **Status:** Active

Blacksville No. 2

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Pittsburgh **County:** Monongalia

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: Consol Energy Inc. **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Byron Payne **Phone Number:** (304) 662-6128

Mailing Address: P.O. Box 24

City: Wana **State:** WV **ZIP** 26590

GENERAL INFORMATION

Number of Employees at Mine: 479 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1971 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 1.97%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,419

Depth to Seam (ft): 1375 **Seam Thickness (ft):** 6.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	3.4	3.9	4.6	5.2	5.2
Estimated Total Methane Liberated (million cf/day):	14.2	13.1	11.1	11.9	9.1
Emission from Ventilation Systems:	8.5	7.8	6.7	7.1	6.7
Estimated Methane Drained:	5.7	5.2	4.4	4.8	2.4
Estimated Specific Emissions (cf/ton):	902	734	524	506	485
Methane Recovered (million cf/day):	0.4	3.8	3.4	1.1	2.1

Estimated Current Drainage Efficiency: 26%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Blacksville No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.3	0.6	0.9
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	2.1%	4.2%	6.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.5%	1.0	1.5

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	39.9	151.0
Mine Electricity Demand:	31.3	120.8
Prep Plant Electricity Demand:	8.6	30.2
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	6.9	60.3
Assuming 40% Recovery Efficiency:	13.8	120.5
Assuming 60% Recovery Efficiency:	20.6	180.8

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.7
Assuming 40% Recovery (Bcf):	1.3
Assuming 60% Recovery (Bcf):	2.0

Description of Surrounding Terrain: Open Low Mountains/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Consolidated Natural Gas Supply Co. (CNG)

Distance to Pipeline (miles): 0.4 **Pipeline Diameter** 10.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Consol is Recovering CMM as part of Multi-Mine Project.

Updated: 04/01/2003 **Status:** Active

Federal No. 2

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Pittsburgh **County:** Monongalia

CORPORATE INFORMATION

Current Owner: Peabody Energy

Parent Company: Peabody Energy **Parent Company Web Site:** www.peabodyenergy.com

Previous Owner(s): Eastern Associated Coal **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Blair McGill **Phone Number:** (304) 449-1911

Mailing Address: 1044 Miracle Run Rd.

City: Fairview **State:** WV **ZIP** 26570

GENERAL INFORMATION

Number of Employees at Mine: 435 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1968 **Primary Coal Use:** Steam

Life Expectancy: 2011 **Sulfur Content of Coal Produced:** 2.0% - 3.2%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 13,300

Depth to Seam (ft): 800 - 1250 **Seam Thickness (ft):** 7.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	4.4	4.8	4.6	4.3	4.3
Estimated Total Methane Liberated (million cf/day):	7.6	11.8	15.3	12.8	17.9
Emission from Ventilation Systems:	4.5	7.1	9.1	7.7	10.7
Estimated Methane Drained:	3.0	4.7	6.1	5.1	7.1
Estimated Specific Emissions (cf/ton):	377	542	719	658	802
Methane Recovered (million cf/day):	0.5	0.6	0.2	1.0	1.0

Estimated Current Drainage Efficiency: 40%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Federal No. 2 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.6	1.2	1.7
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	4.3%	8.6%	12.9%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.0%	2.0	3.0

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	38.7	146.4
Mine Electricity Demand:	30.4	117.1
Prep Plant Electricity Demand:	8.3	29.3
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	13.5	118.5
Assuming 40% Recovery Efficiency:	27.1	237.1
Assuming 60% Recovery Efficiency:	40.6	355.6

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	1.3
Assuming 40% Recovery (Bcf):	2.6
Assuming 60% Recovery (Bcf):	3.9

Description of Surrounding Terrain: Open Low Mountains/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Consolidated Natural Gas Supply Co. (CNG)

Distance to Pipeline (miles): 0.9 **Pipeline Diameter** 10.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Planned DOE Co-funded CMM Power Project

Updated: 04/01/2003 **Status:** Active

Harris No. 1 Mine

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** WV

Coalbed: Eagle **County:** Boone

CORPORATE INFORMATION

Current Owner: Peabody Energy

Parent Company: Peabody Energy **Parent Company Web Site:** www.peabodyenergy.com

Previous Owner(s): Hanson PLC **Previous or Alternate Name of Mine:**

MINE ADDRESS

Contact Name: Harry Stover **Phone Number:** (304) 247-6211

Mailing Address: HCR 78, Box 113

City: Morton **State:** WV **ZIP** 25208

GENERAL INFORMATION

Number of Employees at Mine: 364 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1966 **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: 2005 **Sulfur Content of Coal Produced:** 0.88% - 0.92%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,600

Depth to Seam (ft): 310 **Seam Thickness (ft):** 6.0

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	2.5	3.6	3.0	3.9	3.9
Estimated Total Methane Liberated (million cf/day):	0.7	0.7	0.6	0.8	1.1
Emission from Ventilation Systems:	0.7	0.7	0.6	0.8	1.1
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	101	67	74	70	106
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used:

Harris No. 1 Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.4%	0.7%	1.1%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2	0.3

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	29.1	110.1
Mine Electricity Demand:	22.8	88.1
Prep Plant Electricity Demand:	6.3	22.0
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.8	7.1
Assuming 40% Recovery Efficiency:	1.6	14.2
Assuming 60% Recovery Efficiency:	2.4	21.3

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): < 1.0 **Pipeline Diameter** 8.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Justice #1

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Powellton, Buffalo Creek **County:** Boone

CORPORATE INFORMATION

Current Owner: Independence Coal Co.

Parent Company: Massey Energy Co. **Parent Company Web Site:** www.masseyenergyco.com

Previous Owner(s): **Previous or Alternate Name of Mine:**

MINE ADDRESS

Contact Name: Dwayne Francisco, Pres. **Phone Number:** (180) 076-6132

Mailing Address: HC 78, Box 1800

City: Madison **State:** WV **ZIP** 25130

GENERAL INFORMATION

Number of Employees at Mine: 117 **Mining Method:** Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam, Metallurgical

Life Expectancy: **Sulfur Content of Coal Produced:** NA

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,600

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	0.3	0.8	1.8	3.0	3.0
Estimated Total Methane Liberated (million cf/day):	0.2	0.4	1.4	2.0	2.5
Emission from Ventilation Systems:	0.2	0.4	1.4	2.0	2.5
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	333	171	283	245	275
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used:

Justice #1 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.1	0.2	0.2
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.9%	1.9%	2.8%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.2%	0.4	0.7

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	26.7	100.9
Mine Electricity Demand:	20.9	80.7
Prep Plant Electricity Demand:	5.7	20.2
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	1.9	16.8
Assuming 40% Recovery Efficiency:	3.8	33.6
Assuming 60% Recovery Efficiency:	5.7	50.4

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.2
Assuming 40% Recovery (Bcf):	0.4
Assuming 60% Recovery (Bcf):	0.6

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): < 1.0 **Pipeline Diameter** 8.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Loveridge No. 22

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Pittsburgh **County:** Marion

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: Consol Energy Inc. **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: John Higgins **Phone Number:** (304) 285-2223

Mailing Address: P.O. Box 40

City: Fairview **State:** WV **ZIP** 26570

GENERAL INFORMATION

Number of Employees at Mine: 184 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1953 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 2.69%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,175

Depth to Seam (ft): 1250 **Seam Thickness (ft):** 7.8

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	4.8	5.4	1.1	0.0	0.0
Estimated Total Methane Liberated (million cf/day):	6.8	10.1	0.0	2.7	5.8
Emission from Ventilation Systems:	4.1	6.1	0.0	2.7	3.5
Estimated Methane Drained:	2.7	4.0	0.0	0.1	2.3
Estimated Specific Emissions (cf/ton):	308	406	0		1101
Methane Recovered (million cf/day):	0.2	0.0	0.0	0.0	0.0

Estimated Current Drainage Efficiency: 40%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Loveridge No. 22 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.2	0.4	0.6
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	6.0%	12.0%	17.9%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.4%	2.8	4.2

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	9.1	34.4
Mine Electricity Demand:	7.1	27.5
Prep Plant Electricity Demand:	2.0	6.9
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	4.4	38.3
Assuming 40% Recovery Efficiency:	8.7	76.6
Assuming 60% Recovery Efficiency:	13.1	114.9

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.4
Assuming 40% Recovery (Bcf):	0.8
Assuming 60% Recovery (Bcf):	1.3

Description of Surrounding Terrain: Open Low Mountains/High Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Consolidated Natural Gas Supply Co. (CNG)

Distance to Pipeline (miles): 0.9 **Pipeline Diameter** 10.0

Owner of Next Nearest Pipeline: Kentucky West Virginia Gas Company

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** 6"

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Mc Elroy Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Pittsburgh **County:** Marshall

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: Consol Energy Inc. **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): Consolidation Coal Co. **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Dave Eraskovich, Supt. **Phone Number:** (304) 843-3700

Mailing Address: Rd. 4, Box 425

City: Moundsville **State:** WV **ZIP** 26041

GENERAL INFORMATION

Number of Employees at Mine: NA **Mining Method:** Longwall/Continuous

Year of Initial Production: 1968 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 3.98% -4.42%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,300

Depth to Seam (ft): 600 - 1200 **Seam Thickness (ft):** 5.0 - 5.4

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	5.2	6.6	7.0	6.8	6.8
Estimated Total Methane Liberated (million cf/day):	5.7	5.5	8.0	6.4	6.9
Emission from Ventilation Systems:	4.6	4.6	6.8	6.4	6.9
Estimated Methane Drained:	1.1	0.8	1.2	0.0	0.0
Estimated Specific Emissions (cf/ton):	324	254	355	345	382
Methane Recovered (million cf/day):	0.0	0.0	0.0	0.0	0.0

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Mc Elroy Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.2	0.4	0.7
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.3%	2.7%	4.0%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6	0.9

Power Generation Potential

Utility Electric Supplier: Wheeling Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	52.3	198.0
Mine Electricity Demand:	41.1	158.4
Prep Plant Electricity Demand:	11.2	39.6
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	5.2	45.8
Assuming 40% Recovery Efficiency:	10.5	91.6
Assuming 60% Recovery Efficiency:	15.7	137.4

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.5
Assuming 40% Recovery (Bcf):	1.0
Assuming 60% Recovery (Bcf):	1.5

Description of Surrounding Terrain: High Hills/Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): 0.0 **Pipeline Diameter** 10.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Ohio Power Kammer Plant **Distance to Plant (miles):** 10.0

Comments:

Updated: 04/01/2003 **Status:** Active

Robinson Run No. 95

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Pittsburgh **County:** Harrison

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: Consol Energy Inc. **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** No. 95

MINE ADDRESS

Contact Name: Jimmy Brock **Phone Number:** (304) 795-4421

Mailing Address: Rte. 2, P.O. Box 152

City: Mannington **State:** WV **ZIP** 26582

GENERAL INFORMATION

Number of Employees at Mine: NA **Mining Method:** Longwall/Continuous

Year of Initial Production: 1968 **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 2.95% - 3.14%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 13,100

Depth to Seam (ft): 700 **Seam Thickness (ft):** 6.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	4.8	5.6	5.3	6.0	6.0
Estimated Total Methane Liberated (million cf/day):	5.1	5.1	6.9	5.1	5.0
Emission from Ventilation Systems:	3.1	3.1	4.1	4.1	4.0
Estimated Methane Drained:	2.1	2.0	2.8	1.0	1.0
Estimated Specific Emissions (cf/ton):	235	201	284	247	300
Methane Recovered (million cf/day):	0.0	0.0	0.0	0.0	0.0

Estimated Current Drainage Efficiency: 20%

Drainage System Used: Vertical Gob, Horizontal Pre-Mine

Robinson Run No. 95 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.2	0.3	0.5
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.2%	2.5%	3.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6	0.9

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	38.9	147.3
Mine Electricity Demand:	30.6	117.8
Prep Plant Electricity Demand:	8.4	29.5
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	3.8	33.4
Assuming 40% Recovery Efficiency:	7.6	66.9
Assuming 60% Recovery Efficiency:	11.5	100.3

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.4
Assuming 40% Recovery (Bcf):	0.7
Assuming 60% Recovery (Bcf):	1.1

Description of Surrounding Terrain: Open Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Equitable Gas

Distance to Pipeline (miles): 0.2 **Pipeline Diameter** 10.0

Owner of Next Nearest Pipeline: Consolidated Gas Supply

Distance to Next Nearest Pipeline (miles): 3.0 **Pipeline Diameter** 12.0

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: Harrison **Distance to Plant (miles):** 3.0

Comments: Located Near Power Plant

Updated: 04/01/2003 **Status:** Active

Sentinel Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Kittanning **County:** Barbour

CORPORATE INFORMATION

Current Owner: Philippi Development, Inc.

Parent Company: Anker Energy **Parent Company Web Site:**

Previous Owner(s): **Previous or Alternate Name of Mine:** Ryanstone #1

MINE ADDRESS

Contact Name: Robby Mundy **Phone Number:** (304) 457-1895

Mailing Address: Rte. 3, Box 146

City: Philippi **State:** WV **ZIP** 26416

GENERAL INFORMATION

Number of Employees at Mine: 182

Mining Method: Continuous

Year of Initial Production: 1974

Primary Coal Use: Steam, Metallurgical

Life Expectancy: 2013

Sulfur Content of Coal Produced: 0.96% - 1.34%

Prep Plant Located on Site? Yes

BTUs/lb of Coal Produced: 13,234

Depth to Seam (ft): 425

Seam Thickness (ft): NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	1.1	1.0	0.9	0.5	0.5
Estimated Total Methane Liberated (million cf/day):	2.2	2.5	1.7	1.6	1.4
Emission from Ventilation Systems:	2.2	2.5	1.7	1.6	1.4
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	744	875	689	1177	1208
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used: None

Sentinel Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	3.9%	7.8%	11.8%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.9%	1.8	2.7

Power Generation Potential

Utility Electric Supplier: Philippi Municipal Electric

Parent Corporation of Utility: Municipal Owned

	MW	GWh/year
Total Electricity Demand (2001 data):	3.3	12.3
Mine Electricity Demand:	2.6	9.9
Prep Plant Electricity Demand:	0.7	2.5
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	1.0	9.0
Assuming 40% Recovery Efficiency:	2.1	18.1
Assuming 60% Recovery Efficiency:	3.1	27.1

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.2
Assuming 60% Recovery (Bcf):	0.3

Description of Surrounding Terrain: Open Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Hope Gas

Distance to Pipeline (miles): 0.5 **Pipeline Diameter** NA

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Shoemaker Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Pittsburgh **County:** Marshall

CORPORATE INFORMATION

Current Owner: Consol Energy Inc.

Parent Company: Consol Energy Inc. **Parent Company Web Site:** www.consolenergy.com

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Rock Harris **Phone Number:** (304) 243-4200

Mailing Address: Rd. 1 Box 62 A

City: Dallas **State:** WV **ZIP** 26036

GENERAL INFORMATION

Number of Employees at Mine: NA **Mining Method:** Longwall/Continuous

Year of Initial Production: NA **Primary Coal Use:** Steam

Life Expectancy: **Sulfur Content of Coal Produced:** 3.3%

Prep Plant Located on Site? No **BTUs/lb of Coal Produced:** 12,172

Depth to Seam (ft): 650 **Seam Thickness (ft):** 5.0 - 5.5

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	4.8	4.8	4.4	3.6	3.6
Estimated Total Methane Liberated (million cf/day):	4.8	5.1	5.2	4.3	4.2
Emission from Ventilation Systems:	4.1	4.3	4.4	3.6	3.5
Estimated Methane Drained:	0.7	0.8	0.8	0.6	0.6
Estimated Specific Emissions (cf/ton):	310	325	364	370	316
Methane Recovered (million cf/day):	0.0	0.0	0.0	0.0	0.0

Estimated Current Drainage Efficiency: 15%

Drainage System Used: Vertical Gob

Shoemaker Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.1	0.3	0.4
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	1.3%	2.6%	3.9%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.3%	0.6	0.9

Power Generation Potential

Utility Electric Supplier: Wheeling Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	32.4	122.6
Mine Electricity Demand:	25.4	98.1
Prep Plant Electricity Demand:	7.0	24.5
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	3.2	27.7
Assuming 40% Recovery Efficiency:	6.3	55.3
Assuming 60% Recovery Efficiency:	9.5	83.0

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.3
Assuming 40% Recovery (Bcf):	0.6
Assuming 60% Recovery (Bcf):	0.9

Description of Surrounding Terrain: High Hills/Hills

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): 0.2 **Pipeline Diameter** 10.0

Owner of Next Nearest Pipeline: NA

Distance to Next Nearest Pipeline (miles): NA **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

Upper Big Branch - South

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** WV

Coalbed: Eagle, Powellton **County:** Raleigh

CORPORATE INFORMATION

Current Owner: Performance Coal Co.

Parent Company: Massey Energy Co. **Parent Company Web Site:** www.masseyenergyco.com

Previous Owner(s): **Previous or Alternate Name of Mine:** None

MINE ADDRESS

Contact Name: Homer Wallace **Phone Number:** (304) 854-3308

Mailing Address: P.O. Box 69

City: Naoma **State:** WV **ZIP** 25140

GENERAL INFORMATION

Number of Employees at Mine: 216 **Mining Method:** Longwall/Continuous

Year of Initial Production: NA **Primary Coal Use:** Metallurgical

Life Expectancy: 2018 **Sulfur Content of Coal Produced:** NA

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 12,600

Depth to Seam (ft): NA **Seam Thickness (ft):** NA

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	4.6	5.7	5.1	4.0	4.0
Estimated Total Methane Liberated (million cf/day):	0.5	0.8	1.0	1.2	1.0
Emission from Ventilation Systems:	0.5	0.8	1.0	1.2	1.0
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):	42	53	70	108	125
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used:

Upper Big Branch - South (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.4%	0.9%	1.3%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2	0.3

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	23.4	88.4
Mine Electricity Demand:	18.3	70.7
Prep Plant Electricity Demand:	5.0	17.7
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.8	6.7
Assuming 40% Recovery Efficiency:	1.5	13.4
Assuming 60% Recovery Efficiency:	2.3	20.1

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): < 3.0 **Pipeline Diameter** 8.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

Updated: 04/01/2003 **Status:** Active

US Steel No. 50

GEOGRAPHIC DATA

Basin: Central Appalachian **State:** WV

Coalbed: Pocahontas No. 3 **County:** Wyoming

CORPORATE INFORMATION

Current Owner: U.S. Steel Mining Co., L.L.C.

Parent Company: USX Corp. **Parent Company Web Site:** www.uss.com/ussteel/index.html

Previous Owner(s): None in last 10 years **Previous or Alternate Name of Mine:** Gary No. 50, Pinnacle No.

MINE ADDRESS

Contact Name: Jack Shroder, GM Pinnacle **Phone Number:** (304) 732-5200

Mailing Address: P.O. Box 338

City: Pineville **State:** WV **ZIP** 24824

GENERAL INFORMATION

Number of Employees at Mine: 540 **Mining Method:** Longwall/Continuous

Year of Initial Production: 1969 **Primary Coal Use:** Metallurgical

Life Expectancy: **Sulfur Content of Coal Produced:** 0.75%

Prep Plant Located on Site? Yes **BTUs/lb of Coal Produced:** 14,900

Depth to Seam (ft): NA **Seam Thickness (ft):** 4.2

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	5.0	4.8	3.9	3.7	3.7
Estimated Total Methane Liberated (million cf/day):	14.0	18.0	18.4	16.0	16.6
Emission from Ventilation Systems:	9.7	12.9	14.8	11.0	9.5
Estimated Methane Drained:	4.3	5.0	3.7	5.0	7.1
Estimated Specific Emissions (cf/ton):	713	974	1388	1094	1100
Methane Recovered (million cf/day):	2.8	1.4	2.3	3.5	5.6

Estimated Current Drainage Efficiency: 43%

Drainage System Used: Directional Pre-Mine, Vertical Gob, Horizontal Pre-Mine

US Steel No. 50 (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

(Based on 2001 Data)	Assumed Potential Recovery Efficiency 20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.5	1.1	1.6
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	5.6%	11.1%	16.7%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	1.3%	2.6	3.9

Power Generation Potential

Utility Electric Supplier: Appalachian Power Co.

Parent Corporation of Utility: American Electric Power Co., Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	24.9	94.2
Mine Electricity Demand:	19.5	75.3
Prep Plant Electricity Demand:	5.3	18.8
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	12.6	110.0
Assuming 40% Recovery Efficiency:	25.1	220.1
Assuming 60% Recovery Efficiency:	37.7	330.1

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	1.2
Assuming 40% Recovery (Bcf):	2.4
Assuming 60% Recovery (Bcf):	3.6

Description of Surrounding Terrain: Low Mountains

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Mine owns pipeline that connects to trans. line

Distance to Pipeline (miles): 0.0 **Pipeline Diameter** NA

Owner of Next Nearest Pipeline: Cabot

Distance to Next Nearest Pipeline (miles): 0.5 **Pipeline Diameter** NA

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: None **Distance to Plant (miles):** NA

Comments: Utilizes CDX Gas' Pinnate Technology to Recovery CBM

Updated: 04/01/2003 **Status:** Active

Whitetail Kittanning Mine

GEOGRAPHIC DATA

Basin: Northern Appalachian **State:** WV

Coalbed: Kittanning **County:** Preston

CORPORATE INFORMATION

Current Owner: Coastal Coal Co.

Parent Company: El Paso Corporation **Parent Company Web Site:**

Previous Owner(s): Kingwood Coal Co. **Previous or Alternate Name of Mine:**

MINE ADDRESS

Contact Name: Richard L. Craig **Phone Number:** (304) 568-2460

Mailing Address: Rte. 1, Box 249C

City: Newburg **State:** WV **ZIP** 26410

GENERAL INFORMATION

Number of Employees at Mine: 209

Mining Method: Continuous

Year of Initial Production: NA

Primary Coal Use: Steam

Life Expectancy:

Sulfur Content of Coal Produced: 1.5% - 1.7%

Prep Plant Located on Site? No

BTUs/lb of Coal Produced: 13,150

Depth to Seam (ft): NA

Seam Thickness (ft):

PRODUCTION, VENTILATION AND DRAINAGE DATA

	1997	1998	1999	2000	2001
Coal Production (million short tons/year):	0.0	0.0	0.0	0.3	0.3
Estimated Total Methane Liberated (million cf/day):	0.0	0.0	0.0	0.1	0.9
Emission from Ventilation Systems:	0.0	0.0	0.0	0.1	0.9
Estimated Methane Drained:	0.0	0.0	0.0	0.0	0.0
Estimated Specific Emissions (cf/ton):				158	142
Methane Recovered (million cf/day):					

Estimated Current Drainage Efficiency: 0%

Drainage System Used:

Whitetail Kittanning Mine (continued)

ENERGY AND ENVIRONMENTAL VALUE OF EMISSIONS REDUCTIONS

	Assumed Potential Recovery Efficiency		
(Based on 2001 Data)	20%	40%	60%
CO_2 Equivalent of CH_4 Emissions Reductions (mm tons)	0.0	0.1	0.1
CO_2 Equivalent of CH_4 Emissions Reductions/CO_2 Emissions from Coal Combustion:	0.5%	0.9%	1.4%
BTU Value of Recovered Methane/BTU Value of Coal Produced:	0.1%	0.2	0.3

Power Generation Potential

Utility Electric Supplier: Monongahela Power Co.

Parent Corporation of Utility: Allegheny Power Systems, Inc.

	MW	GWh/year
Total Electricity Demand (2001 data):	18.9	71.5
Mine Electricity Demand:	14.8	57.2
Prep Plant Electricity Demand:	4.1	14.3
Potential Generating Capacity (2001 data)		
Assuming 20% Recovery Efficiency:	0.7	6.2
Assuming 40% Recovery Efficiency:	1.4	12.3
Assuming 60% Recovery Efficiency:	2.1	18.5

Pipeline Sales Potential

Potential Annual Gas Sales (2001 data)	Bcf
Assuming 20% Recovery (Bcf):	0.1
Assuming 40% Recovery (Bcf):	0.1
Assuming 60% Recovery (Bcf):	0.2

Description of Surrounding Terrain:

Transmission Pipeline in County? Yes

Owner of Nearest Pipeline: Columbia Gas Transmission Co.

Distance to Pipeline (miles): ~10.0 **Pipeline Diameter** 10.0

Owner of Next Nearest Pipeline:

Distance to Next Nearest Pipeline (miles): **Pipeline Diameter**

Other Utilization Possibilities

Name of Nearby Coal Fired Power Plant: NA **Distance to Plant (miles):** NA

Comments:

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References and Calculations Used in the Mine Profiles

Data Item	Sources	Calculations
Geographic Data (State, County, Basin, Coalbed)	Keystone (2002)	
Corporate Information:		
Current Owner	Past versions of Keystone Coal Manual and recent coal industry publications	
Previous Owner	Past versions of Keystone Coal Manual and Coal Magazine Annual Longwall Surveys	
Parent Company	Past versions of Keystone Coal Manual and recent coal industry publications	
Phone/Address/Contact Information	Past versions of Keystone Coal Manual and EIA reports.	
General Information:		
Number of Employees	Past versions of Keystone Coal Manual	
Year of Initial Production	MSHA; Past versions of Keystone Coal Manual and articles in coal industry publications	
Life Expectancy:	Past versions of Keystone Coal Manual	
Sulfur Content	Past versions of Keystone Coal Manual	
Mining Method	Past versions of Keystone Coal Manual and Coal Magazine Longwall Survey	
Primary Use	Past versions of Keystone Coal Manual	
Production, Ventilation, and Drainage Data		
Coal Production	MSHA (2002)	
Emissions from Ventilation Systems	MSHA (1997 - 2002)	
Estimated Methane Drained	The number of mines assumed to have drainage systems is based on calls to individual MSHA districts.	Drainage emissions are estimated by assuming that they are 40% of total liberation, unless otherwise noted.

Data Item	Sources	Calculations
Estimated Total Methane Liberated		Sum of "emissions from ventilation systems" and "estimated methane drained."
Degasification Information		
Drainage system Used	Based on calls to individual MSHA districts offices.	
Estimated Current Drainage Efficiency		Assumed to be 40% unless otherwise noted for mines where the drainage efficiency is known.
Energy and Environmental Value		
CO_2 Equivalent of Methane Emissions Reductions (mm tons)	Global Warming Potential of Methane Compared to CO_2 based on IPCC (1997). GWP is 21 over 100 years.	Estimated 2001 CH_4 liberated (mmcf) x recovery efficiency x 19.2 g/cf x 21 g CO_2/1 g CH_4 x 1 lb / 453.59 g x 1 ton / 2000 lbs
CO_2 Equivalent of Methane Emissions Reductions/CO_2 Emissions from Coal Combustion	CO_2/BTU ratio based on average state values in EIA (1992)	Fraction = [CO_2 equivalent of CH_4 emissions reductions (lbs)] / [1996 coal production (tons) x BTUs/ton x CO_2 emitted lbs/BTU x 99% (fraction oxidized)
BTU Value of Recovered Methane/BTU Value of Coal Produced	BTU/ton value for coal production based on information in Keystone or on average state values from EIA (2002)	Fraction = [2001 CH_4 liberated (cf/yr) x rec. efficiency x 1000 BTUs/cf] / [1996 coal production (tons) x BTUs/ton]
Power Generation Potential		
Electricity Supplier	Directory of Electric Utilities	
Potential Electric Generating Capacity		Capacity = Estimated CH_4 liberated in cf/day x recovery efficiency x 1 day/24 hours x 1000 BTUs/cf x kwh/11000 BTUs
Mine Electricity Demand	Mine electricity needs (24 kwh/ton) is based on ICF Resources (1990a) Ventilation systems are assumed to account for 25% of total electricity demand and to run 24 hours a day (8760 hours/year). Other mine operations are assumed to account	Demand (MW) = Demand from Ventilation Systems + Demand from Mine Operations + Demand from Prep Plant Demand (MW) ventilation systems = [25% x 24 kwh/ton x tons/year]/

Data Item	Sources	Calculations
	for 75% of electricity demand and to run 16 hours a day 220 days per year (3520 hours/year).	[8760 hours/year] Demand (MW) mine operations = [75% x 24 kwh/ton x tons/year]/ [3520 hours/year] Demand (GWh/year) = Demand from Mine + Demand from Prep. Plant Demand from Mine = [24 kwh/ton x tons/year]/ 10^6 Demand from Prep. Plant = [6 kwh/ton x tons/year]/ 10^6
Prep Plant Electricity Demand	Based on Keystone Coal Manual (2002) and Coal magazine annual Prep Plant surveys. If tons processed per year at the prep plant is available in the Keystone, then that value is used. Otherwise, coal processed is assumed to be equal to mine production. Prep plant electric needs of 6 kwh/ton based on ICF Resources (1990a). Prep plants are assumed to operate 3520 hours/year.	Demand (MW) prep plant = [6 kwh/ton x tons/year]/ 3520 hours/year]
Pipeline Potential		
Potential Annual Gas Sales		Estimated methane liberated (mmcf/d) x 365 days/yr x recovery efficiency
All other information	ICF Resources (1990b)	
Other Utilization Potential		
Name of Coal Fired Boiler Located Near Mine (if any)	Electric Power (2001)	
Distance to Boiler	Electric Power (2001)	